UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

February 3, 2010

John T. Conway
Senior Vice President – Energy Supply and
Chief Nuclear Officer
Pacific Gas and Electric Company
77 Beale Street, B32
San Francisco, CA 94105

Subject: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2009005 AND 05000323/2009005

Dear Mr. Conway:

On December 31, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Diablo Canyon Power Plant. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 4, 2010, with Mr. James Becker, Site Vice President, and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents two self-revealing and one NRC-identified finding of very low safety significance (Green), and two NRC-identified Severity Level IV violations. All of these findings were determined to involve violations of NRC requirements. In addition, one licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as a noncited violations, consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the violations or the significance of the noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 612 E. Lamar Blvd, Suite 400, Arlington, Texas, 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Diablo Canyon Power Plant. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at the Diablo Canyon Power Plant. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document

Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Geoffrey B. Miller, Chief
Project Branch B
Division of Reactor Projects

Docket: 50-275
50-323
License: DPR-80
DPR-82

Enclosure:
NRC Inspection Report 05000/275/2009005 and 0500323/2009005
w/Attachment: Supplemental Information

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Publicly Avail	☑ Yes ☐ No	Sensitive	☐ Yes ☑ No	Sens. Type Initials	GM

RIV:RI:DRP/B	SRI:DRP/B	C:DRP/B	C:DRS/EB2	C:DRS/PSB1
MABrown	MSPeck	GBMiller	NOkeefe	MPShannon
/RA by Email/	***/RA by Email/***	***/RA/***	***/RA/***	***/RA/***
2/3/10	2/2/10	2/3/10	1/28/10	2/1/10
C:DRS/PSB2	C:DRS/EB1	C:DRS/OB		
GEWerner	TFarnholtz	SGarchow		
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1/29/10	2/1/10	1/2910		

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000275, 05000323
License:	DPR-80, DPR-82
Report:	05000275/2009005 05000323/2009005
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	September 26 through December 31, 2009
Inspectors:	M. S. Peck, Senior Resident Inspector M. A. Brown, Resident Inspector S. T. Makor, Reactor Inspector, Engineering Branch 1 G. A. George, Reactor Inspector, Engineering Branch 1 D. C. Graves, Health Physicist N. A. Greene, Health Physicist G. L. Guerra, CHP, Emergency Preparedness Inspector
Approved By:	G. B. Miller, Chief, Project Branch B Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000275/2009005, 05000323/2009005; 9/26/2009 – 12/31/2009; Diablo Canyon Power Plant, Integrated Resident and Regional Report; Refueling and Other Outage Activities; Identification and Resolution of Problems; ALARA Planning and Controls; Other Activities.

The report covered a 3-month period of inspection by resident inspectors and announced baseline inspections by regional based inspectors. Three Green noncited violations of significance and two Severity Level IV noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a noncited violation of Title 10 CFR, Part 50, Appendix B, Criterion II, "Design Control," after the design contractor failed to perform adequately calculations demonstrating that the replacement reactor head met ASME Code acceptance criteria. The contractor failed to use the critical seismic damping values specified in the plant design basis for the design of the integrated head assembly and the control rod drive mechanism housing assembly and when calculating component stress during a postulated design basis earthquake. The licensee entered this condition into the corrective action program as Notifications 50276107 and 50276288.

  The inspectors concluded that the failure to properly implement the plant design basis in the replacement head design was a performance deficiency. The finding is more than minor because the performance deficiency is associated with the Initiating Events Cornerstone design control attribute and adversely affected the cornerstone objective to limit the likelihood of loss of a coolant accident during a seismic event. The inspectors determined the finding is of very low safety significance because assuming worst case degradation, the finding would not result in exceeding the Technical Specification limit for reactor coolant system leakage nor have likely affected other mitigation systems resulting in a total loss of their safety function. This finding has a crosscutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee did not identify the use of improper damping values with a low threshold for identifying issues during oversight of contractor activities and design reviews, [P.1(a)] (Section 4OA5).

- Severity Level IV. The inspectors identified a Severity Level IV noncited violation of 10 CFR 50.59 after the licensee failed to perform an adequate evaluation to demonstrate that prior NRC approval was not required before making changes to the facility as described in the Final Safety Analysis Report Update. In October 2009, the inspectors identified that the replacement reactor head contractor used incorrect damping values in the replacement head design. The contractor was unable to demonstrate that the design met ASME Code using the damping values specified in the plant design basis. On November 5, 2009, the licensee incorporated the new damping values and revised the method for determining the seismic response spectra. Using NEI 96-07, "Guidelines for 10 CFR 50.59 Evaluations," Revision 1, the inspectors concluded that these changes resulted in a departure from a method of evaluation described in the Final Safety Analysis Report Update establishing the facility design bases. The licensee's 50.59 evaluation, Licensing Basis Impact Evaluation LBIE 2009-021, "Integrated Head Assembly," was less than adequate to conclude that prior NRC approval was not required for the changes. The licensee entered this issue into their corrective action program as 50276288.

The failure of Pacific Gas and Electric to perform an adequate 10 CFR 50.59 evaluation prior to changing the facility as described in the Final Safety Analysis Report Update is a performance deficiency. The inspectors evaluated this issue using the traditional enforcement process because the performance deficiency had the potential for impacting the NRC's ability to perform its regulatory function. The inspectors concluded that the issue was more than minor because of a reasonable likelihood the change to the facility would require Commission review and approval prior to implementation. The inspectors also evaluated this issue using the Significance Determination Process. The inspectors concluded that the violation affected the Initiating Events Cornerstone because the change potentially decreased the structural integrity of the control rod drive mechanism reactor coolant pressure barrier and screened Green because assuming worst case degradation, the finding would not result in exceeding the technical specification limit for reactor coolant system leakage nor have a likely effect on other mitigation systems resulting in a total loss of their safety function. The inspectors concluded that the violation was a Severity Level IV because the issue screened Green under the Significance Determination Process. The finding has a crosscutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee did not thoroughly evaluate the original problem associated with the replacement reactor head design such that the resolutions address causes and extent of conditions, as necessary [P.1(c)] (Section 4OA5).

Cornerstone: Mitigating Systems

- Severity Level IV. The inspectors identified a Severity Level IV noncited violation of 10 CFR 50.59 after Pacific Gas and Electric failed to perform an adequate evaluation of a change to the facility as described in the Final Safety Analysis Report Update. In 1992, the licensee identified that auxiliary feedwater and steam generator power-operated relief valve flow rates assumed in the steam generator tube rupture accident analysis were non-conservative. To address the non-conforming condition, Pacific Gas and Electric changed the accident analysis to include a new time critical operator action to terminate turbine-driven auxiliary feedwater flow 5.54 minutes after the reactor trip and credit motor driven auxiliary feedwater automatic level control to the ruptured steam generator. The licensee did not perform a 10 CFR 50.59 safety evaluation of these changes. The NRC basis of approval of the accident analysis include four time critical operator actions, each assumed to occur after the first 10 minutes following the accident. The inspectors concluded that NRC approval was required before the licensee added the new time critical manual action under the 10 CFR 50.59 Rule in effect at the time because the change reduced the margin to safety to the basis of Technical Specification 3.7.4, "10% Atmospheric Dump Valves." The inspectors also concluded that prior NRC approval was required under the current 50.59 Rule because the change result in a departure from a method of evaluation described in the Final Safety Analysis Report Update. The performance deficiency, a less than adequate 50.59 evaluation, was the result of a latent issue. However, the inspectors concluded that the licensee had reasonable recent opportunities to identify the problem. The inspectors also concluded that plant programs, processes or organizations have not changed such that the problem would not reasonably occur today and that the most significant contributor to the performance deficiency was reflective of current plant performance. The licensee entered this issue into their corrective action program as Notification 50270786.

The failure of Pacific Gas and Electric to perform a 10 CFR 50.59 evaluation of the changes to the steam generator tube rupture accident analysis was a performance deficiency. The inspectors evaluated this issue using traditional enforcement because the performance deficiency had the potential for impacting the NRC's ability to perform its regulatory function. The issue was more than minor because of reasonable likelihood the change to the facility would require Commission review and approval prior to implementation. The inspectors also evaluated the significance of this issue under the Significance Determination Process using Inspection Manual Chapter 0609.04, "Phase 1 - Initial Screening and Characterization of Findings." The finding affected the Mitigating Systems Cornerstone because the change described the operator actions required to mitigate steam generator tube rupture accident. The inspectors concluded the finding screened Green because the finding was a design deficiency that did not result in the loss of operability or functionality. The inspectors concluded that the violation was a Severity Level IV because the issue screened Green under the Significance Determination Process. The inspectors concluded that this finding had a crosscutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee did not thoroughly evaluate the steam generator tube rupture analysis such that the resolutions addressed causes and extent of condition [P.1(c) (Section 4OA2).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a self-revealing noncited violation of Technical Specification 5.4.1, "Procedures," after Pacific Gas and Electric inadvertently released the contents of two gas decay tanks into the auxiliary building. Gas Decay Tank 2-2 was in "purge mode." On October 11, 2009, plant operators were implementing an equipment control clearance to drain the emergency core cooling systems. A second group of operators were implementing a core offload master clearance. The parallel implementation of both equipment clearances resulted in Gas Decay Tank 2-2 to be vented into the auxiliary building. The auxiliary building operator received a low gas header pressure alarm after the pressure dropped to 15 psig. Per procedure, the operator aligned Gas Decay Tank 2-3 to "purge" mode. As a result, the second gas decay tank was released into the auxiliary building through the open vent path. The inspectors concluded that the radiological consequence of the event did not result in a potential for overexposure because the reactor had been shutdown since October 3, 2009.

The inspectors concluded that the failure to properly implement the core offload master equipment control clearance was a performance deficiency. The finding is more than minor because the performance deficiency could be reasonably viewed as a precursor to a significant event. The inspectors determined the finding to have very low safety significance because the performance deficiency only represented a degradation of the auxiliary building radiological barrier function. This finding has a crosscutting aspect in the area of human performance associated with the work control component because the licensee did not adequately plan and coordinate the two clearance activities or fully consider the impact the work had on different job activities and the need for the two work groups to maintain interfaces [H.3(b)] (Section 1R20).

Cornerstone: Occupational Radiation Safety

Green. The inspectors reviewed a self-revealing, noncited violation of Technical Specification 5.4.1(a) for failure to properly plan numerous outage maintenance activities including the disassembly of the Unit 2 reactor head. Specifically, Work Orders 68004363 (disassembly of the old head) and 68003988 (scaffolding activities) were not properly planned, thereby requiring those maintenance activities to be changed and/or repeated, which resulted in increased radiation exposure. Radiation Work Permits 09-2233 and 09-2237 for the disassembly of the Unit 2 old reactor vessel closure head and supporting activities during Refueling Outage 15 had an initial combined dose estimate of 5.869 rem and 1102 man-hours. However, the job ended with an actual combined dose of 17.378 rem and 1882 man-hours, which exceeded the initial dose estimate by 296 percent. The overarching reason for exceeding the original dose estimate was improper planning and control for the maintenance, which increased the man-hours to complete the task by 170 percent. The licensee entered this deficiency in the corrective action program as Notification 50275107 and plan to perform an apparent cause evaluation.

The failure to properly plan maintenance activities is a performance deficiency. This finding is greater than minor because it affected the Occupational Radiation Safety cornerstone attribute of Program and Process in that the inadequate ALARA planning caused increased collective radiation dose for the job activity to exceed 5 person-rem and the planned dose by more than 50 percent. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined this finding to be of very low safety significance because although it involved ALARA planning and controls, the licensee's latest rolling three-year average does not exceed 135 person-rem per unit. Furthermore, the finding had an associated human performance cross-cutting aspect in the work control component because the licensee did not fully incorporate job site conditions, plant structures, systems, and components, as well as human-system interface and the need for planned contingencies to maintain doses ALARA [H.3(a)].

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective action tracking numbers are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

At the beginning of the inspection period, Pacific Gas and Electric Company was operating Diablo Canyon Units 1 and 2 at full power. Plant operators reduced Unit 1 reactor power to 50 percent following marine fouling of the main condenser on October 15, 2009. Plant operators returned Unit 1 to full power on October 16, 2009 after successfully completing condenser cleaning activities. Plant operators shut down Unit 2 on October 3, 2009 to begin refueling outage 2R15. Operators restarted Unit 2 on November 10, 2009 after completion of the refueling outage and returned Unit 2 to full power on November 15, 2009. Pacific Gas and Electric continued to operate both Units at full power through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Readiness to Cope with External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the Final Safety Analysis Report Update (FSARU) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site that would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also reviewed the abnormal operating procedure for mitigating the design basis flood to ensure it could be implemented as written. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one external flooding sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Equipment Walk-downs

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk significant systems:

- Unit 1, Emergency Diesel Generator 1-1, October 6, 2009

- Unit 2, spent fuel pool cooling system, October 19, 2009

- Unit 1, charging system, November 17, 2009

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could affect the function of the system; and therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, final safety analysis report update, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three partial system walkdown samples as defined by Inspection Procedure 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk significant plant areas:

- Unit 1, residual heat removal pump rooms, Fire Areas 3-B-1, 3-B-2, and 3-B-3, October 15, 2009

- Unit 1, centrifugal charging pump rooms, Fire Areas 3-H-1 and 3-H-2, October 19, 2009

- Units 1 and 2, intake structure, Fire Area 30-A-5, October 27, 2009

- Unit 1, emergency diesel generator rooms, Fire Areas TB-1, TB-2, and TB-3, December 8, 2009

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four quarterly fire protection inspection samples as defined by Inspection Procedure 71111.05-05.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors reviewed the FSARU, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; and corrective action program to determine if licensee personnel identified and corrected flooding problems; inspected underground bunkers/manholes to verify the adequacy of sump pumps, level alarm circuits, cable splices subject to submergence, and drainage for bunkers/manholes; verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and walked down the two areas listed below to verify the adequacy of equipment seals located below the flood line, floor and wall penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, and control circuits, and temporary or removable flood barriers. Specific documents reviewed during this inspection are listed in the attachment.

- October 15, 2009, Unit 2, circulating water pump, auxiliary saltwater pump, and Bus G underground bunkers
- October 19, 2009, Unit 1, residual heat removal pump rooms

These activities constitute completion of two flood protection measures inspection samples as defined by Inspection Procedure 71111.06-05.

b. Findings

No findings of significance were identified.

1R08 In-service Inspection Activities (71111.08)

.1 Inspection Activities Other Than Steam Generator ***/RA by Email/*** Tube Inspection, Pressurized Water Reactor Vessel Upper Head Penetration Inspections, and Boric Acid Corrosion Control (71111.08-02.01)

a. Inspection Scope

The inspectors reviewed 25-nondestructive examination activities, welding activities, and one weld on the reactor coolant system pressure boundary. The inspectors also reviewed two examinations with relevant indications that had been accepted by licensee personnel for continued service.

The inspectors directly observed the following nondestructive examinations:

SYSTEM	WELD IDENTIFICATION	EXAMINATION TYPE
Loop 1 pressurizer spray line	WIB 59B	Ultrasonic Testing
Charging Line Loop 4	WIB 312	Ultrasonic Testing
Charging Line Loop 4	WIB 314	Ultrasonic Testing
Safety Injection Accumulator Loop 4	WIB 291	Ultrasonic Testing

The inspectors reviewed records for the following nondestructive examinations:

SYSTEM	IDENTIFICATION	EXAMINATION TYPE
Replacement Reactor Vessel Head, Unit 2	WH-11	Radiography Testing
Replacement Reactor Vessel Head, Unit 2	WH-12	Penetrant Testing
Replacement Reactor Vessel Head, Unit 2	WH-2, First and Final Layer	Visual Testing
Replacement Reactor Vessel Head, Unit 2	WH-3, Clad Thickness Examination	Ultrasonic Testing
Replacement Reactor Vessel Head, Unit 2	WH-5 Bond and Defect	Ultrasonic Testing
Replacement Reactor Vessel Head, Unit 2	Under Clad Cracking Examination	Ultrasonic Testing
Replacement Reactor Vessel Head, Unit 2	Dissimilar Metal Welds ILH, TC, Vent, and RVLIS	Penetrant Testing
Replacement Reactor Vessel Head, Unit 2	WH-09 and WH-10	Visual Testing

SYSTEM	IDENTIFICATION	EXAMINATION TYPE
Replacement Reactor Vessel Head, Unit 2	WH-13	Penetrant Testing
Replacement Reactor Vessel Head, Unit 2	WH-12*	Radiography Testing
Residual Heat Removal System, Unit 2	RB-119-11*	Ultrasonic Testing
Reactor Coolant System, Unit 1	WIB-RC-2-1 (SE), WIB-RC-2-1	Ultrasonic Testing, Eddy Current Testing
Reactor Coolant System, Unit 1	WIB-RC-1-1(SE), WIB-RC-1-1	Ultrasonic Testing, Eddy Current Testing
Reactor Coolant System, Unit 1	WIB-RC-3-18 (SE), WIB-RC-3-18	Ultrasonic Testing, Eddy Current Testing
Pressurizer, Safety Nozzle A	WIB-368-369 O.L.	Ultrasonic Testing
Pressurizer, Safety Nozzle B	WIB-422A-423 O.L.	Ultrasonic Testing
Pressurizer, Safety Nozzle C	WIB-358-359 O.L.	Ultrasonic Testing
Pressurizer, Relief Nozzle	WIB-379-380 O.L.	Ultrasonic Testing
Pressurizer, Spray Nozzle	WIB-345-346 O.L.	Ultrasonic Testing
Pressurizer, Surge Nozzle	WIB-438-439 O.L.	Ultrasonic Testing
Safety Injection System	FW 7	Radiography Testing

During the review and observation of each examination, the inspectors verified that activities were performed in accordance with the ASME Code requirements and applicable procedures. The inspectors compared indications from previous examinations and verified that licensee personnel resolved the indications in accordance with the ASME Code and approved procedures. Additionally, the inspectors verified the qualifications of all nondestructive examination technicians performing the inspections were current.

The inspectors verified, by review, that the welding procedure specifications and the welders had been properly qualified in accordance with ASME Code, Section IX, requirements. The inspectors also verified, through observation and record review, that essential variables for the welding process were identified, recorded in the procedure qualification record, and formed the bases for qualification of the welding procedure specifications. Specific documents reviewed during this inspection are listed in the attachment.

These actions constitute completion of the requirements for Section 02.01.

b. Findings

No findings of significance were identified.

.2 Vessel Upper Head Penetration Inspection Activities (71111.08-02.02)

a. Inspection Scope

During this inspection, the licensee was in the process of replacing the reactor vessel closure head. Therefore, the licensee did not perform vessel upper head penetration inspection activities during this inspection.

The inspectors reviewed the results of the ASME Code pre-service examination for the Unit 2 reactor vessel replacement closure head. The inspectors verified that ASME Code allowable indications identified during the examination were documented in accordance with ASME Code. The inspectors verified that the personnel performing the visual inspection were certified as Level II and Level III eddy current, ultrasonic, and visual examiners.

These actions constitute completion of the requirements for Section 02.02.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control Inspection Activities (71111.08-02.03)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's boric acid corrosion control program for monitoring degradation of those systems that could be adversely affected by boric acid corrosion. The inspectors reviewed the documentation associated with the licensee's boric acid corrosion control walkdown as specified in Procedure ERD1.IDR, "Boric Acid Corrosion Control Program," Revision 4. The inspectors also reviewed the visual records of the components and equipment. The inspectors verified that the visual inspections emphasized locations where boric acid leaks could cause degradation of safety-significant components. The inspectors also verified that the engineering evaluations for those components where boric acid was identified gave assurance that the ASME Code wall thickness limits were properly maintained. The inspectors confirmed that the corrective actions performed for evidence of boric acid leaks were consistent with requirements of the ASME Code. Specific documents reviewed during this inspection are listed in the attachment.

These actions constitute completion of the requirements for Section 02.03.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities (71111.08-02.04)

a. Inspection Scope

This was the first inspection performed after replacing the steam generators per the Electric Power Research Institute (EPRI) guidelines and it consisted of a 100 percent inspection of all tubes.

The inspection procedure specified performance of an assessment of in situ screening criteria to assure consistency between assumed nondestructive examination flaw sizing accuracy and data from the EPRI examination technique specification sheets. It further specified assessment of appropriateness of tubes selected for in situ pressure testing, observation of in situ pressure testing, and review of in situ pressure test results.

At the time of this inspection, no conditions had been identified that warranted in situ pressure testing. The inspectors did, however, review the licensee's report for Unit 2 "Steam Generator Degradation Assessment," dated October 11, 2009. This review determined that the remaining screening parameters were consistent with the EPRI guidelines.

In addition, the inspectors reviewed both the licensee site-validated and qualified acquisition and analysis technique sheets used during this refueling outage and the qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy, tubing, equipment, technique, and analysis had been identified and qualified through demonstration. The inspectors reviewed acquisition technique and analysis technique sheets are identified in the Attachment.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability. No new damage mechanisms had been identified during this inspection which was expected, since this was the first inspection following the replacement of the steam generator.

The inspection procedure specified confirmation that the steam generator tube eddy current test scope and expansion criteria meet Technical Specification requirements, EPRI guidelines, and commitments made to the NRC. The inspectors evaluated the recommended steam generator tube eddy current test scope established by Technical Specification requirements and the licensee’s degradation assessment report. The inspectors compared the recommended test scope to the actual test scope and found that the licensee had accounted for all known flaws and had, as a minimum, established a test scope that met Technical Specification requirements, EPRI guidelines, and commitments made to the NRC.

The inspection procedure specified, if new degradation mechanisms were identified, verify that the licensee fully enveloped the problem in its analysis of extended conditions including operating concerns and had taken appropriate corrective actions before plant startup. The eddy current test results had not identified any new degradation mechanisms.

The inspection procedure requires confirmation that the licensee inspected all areas of potential degradation, especially areas that were known to represent potential eddy current test challenges (e.g., top-of-tube sheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation were included in the scope of inspection and were being inspected.

The inspection procedure further requires verification that repair processes being used were approved in the Technical Specifications; confirmation of adherence to the Technical Specification plugging limit, unless alternate repair criteria have been approved; and determination whether depth sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors reviewed relevant documentation, but did not conduct any assessment because these conditions did not exist.

If steam generator leakage greater than 3 gallons per day was identified during operations or during post shutdown visual inspections of the tube sheet face, the inspection procedure requires verification that the licensee had identified a reasonable cause based on inspection results and that corrective actions were taken or planned to address the cause for the leakage. The inspectors did not conduct any assessment because this condition did not exist.

The inspection procedure requires confirmation that the eddy current test probes and equipment were qualified for the expected types of tube degradation and an assessment of the site specific qualification of one or more techniques. The inspectors observed portions of eddy current tests performed. During these examinations, the inspectors verified that: (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered, and (4) probe travel speed was in accordance with procedural requirements. The inspectors performed a review of site specific qualifications of the techniques being used. Specific documents reviewed during this inspection are listed in the attachment.

If loose parts or foreign material on the secondary side were identified, the inspection procedure specified confirmation that the licensee had taken or planned appropriate repairs of affected steam generator tubes and that they inspected the secondary side to either remove the accessible foreign objects or perform an evaluation of the potential effects of inaccessible object migration and tube fretting damage. At this time of the inspection, the foreign material identified was too small to affect steam generator integrity.

Finally, the inspection procedure specified review of one to five samples of eddy current test data if questions arose regarding the adequacy of eddy current test data analyses. The inspectors did not identify any results where eddy current test data analyses adequacy was questionable.

These actions constitute completion of the requirements of Section 02.04.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems (71111.08-02.05)

a. Inspection scope

The inspectors reviewed 8 condition reports which were associated with inservice inspection activities and found the corrective actions were appropriate. The specific condition reports reviewed are listed in the documents reviewed section. From this review, the inspectors concluded that the licensee has an appropriate threshold for entering issues into the corrective action program and has procedures that direct a root cause evaluation when necessary. The licensee also has an effective program for applying industry operating experience. Specific documents reviewed during this inspection are listed in the attachment.

These actions constitute completion of the requirements of Section 02.05.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On December 15, 2009, the inspectors observed a crew of licensed operators in the plant's simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Crew's ability to take timely actions in the conservative direction
- Crew's prioritization, interpretation, and verification of annunciator alarms
- Crew's correct use and implementation of abnormal and emergency procedures
- Control board manipulations
- Oversight and direction from supervisors
- Crew's ability to identify and implement appropriate technical specification actions and emergency plan actions and notifications

The inspectors compared the crew's performance in these areas to pre-established operator action expectations and successful critical task completion requirements. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one quarterly licensed operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- Notification 50241125, goal setting evaluation after Chemical Volume Control System Valve 1-8109 failed to meet local leak rate testing acceptance criteria
- Notification 50264326, corrective action plan and goal setting evaluation for Containment Fan Cooler 1-5 following 405 hours of unavailability.
- Notification 50044666, ineffective correction actions for main transformers

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices
- Identifying and addressing common cause failures
- Scoping of systems in accordance with 10 CFR 50.65(b)
- Characterizing system reliability issues for performance
- Charging unavailability for performance
- Trending key parameters for condition monitoring
- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or (a)(2)
- Verifying appropriate performance criteria for structures, systems, and components classified as having an adequate demonstration of performance through preventive maintenance, as described in 10 CFR 50.65(a)(2), or as requiring the establishment of appropriate and adequate goals and corrective actions for systems classified as not having adequate performance, as described in 10 CFR 50.65(a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk significant and safety related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Technical Specification Tracking Sheet 1-TS-09-0878, removal of 230 kV offsite power source, October 6, 2009

- Technical Specification Tracking Sheet 1-TS-09-0908, startup Transformer 1-1 cleared to inspect lightning arrestor bushing, October 14, 2009

- Technical Specification Tracking Sheet 1-TS-09-0975, startup Transformer 1-1 cleared to clean lightning arrestors, November 16, 2009

The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three maintenance risk assessments and emergent work control inspection samples as defined by Inspection Procedure 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- Notification 50265431, temperature limits exceeded per Equipment Control Guideline 23.1

- Action Request A0733045, Unit 2 Inverter 2-3 room exceeded 103° F for greater than 8 hours

- Notification 50274623 and Notification 50274625, Unit 1, Radiation Monitors RM-25 and RM-26 reading upscale, October 13, 2009

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and the updated safety analysis report to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three operability evaluations inspection samples as defined in Inspection Procedure 71111.15-05.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

Temporary Modifications

a. Inspection Scope

To verify that the safety functions of important safety systems were not degraded, the inspectors reviewed the temporary modification identified as Work Order 60014416, Unit 1, substitution of Wide Range Reactor Coolant System Temperature Detector, TE-413B, with spare Narrow Range Temperature Detector, TE-411B.

The inspectors reviewed the temporary modification and the associated safety-evaluation screening against the system design bases documentation, including the FSARU and the Technical Specifications, and verified that the modification did not adversely affect the system operability/availability. The inspectors also verified that the installation and restoration were consistent with the modification documents and that configuration control was adequate. Additionally, the inspectors verified that the temporary modification was identified on control room drawings, appropriate tags were placed on the affected equipment, and licensee personnel evaluated the combined effects on mitigating systems and the integrity of radiological barriers.

These activities constitute completion of one sample for temporary plant modifications as defined in Inspection Procedure 71111.18-05.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Work Orders 60005322 and 60005323, Unit 1, change of motor pinion gears for Valves SI-1-8982A and B February 27, 2009
- Work Order 68006480, Unit 2, digital rod position indicator and integrated head assemble installation test, September 10, 2009
- Work Order 68007283, Unit 2, digital rod position indicator replacement, October 21, 2009
- Work Order 64045014, Unit 2, engineering safeguards valve interlock testing, October 22, 2009
- Work Order 68004063, Unit 2, replacement reactor head hydro, November 1, 2009
- Work Order 68004002, Unit 1, replace Diesel Generator 1-1 Recorder with Yokogawa, December 9, 2009
- Work Order 64009270, Unit 1 Safety Injection Pump 1-2 preventive maintenance, December 14, 2009
- Work Order 64014692, Unit 2, Residual Heat Removal Pump 2-1 preventive maintenance, December 17, 2009

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities for the following (as applicable):

- The effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed
- Acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate

The inspectors evaluated the activities against the technical specifications, the FSARU, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of eight postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the outage safety plan and contingency plans for the Unit 2 refueling outage, conducted between October 3 and November 10, 2009 to confirm that licensee personnel had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Configuration management, including maintenance of defense-in-depth, is commensurate with the outage safety plan for key safety functions and compliance with the applicable technical specifications when taking equipment out of service.

- Clearance activities, including confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.

- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.

- Status and configuration of electrical systems to ensure that technical specifications and outage safety-plan requirements were met, and controls over switchyard activities.

- Monitoring of decay heat removal processes, systems, and components.

- Verification that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.

- Reactor water inventory controls, including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.

- Controls over activities that could affect reactivity.

- Maintenance of secondary containment as required by the technical specifications.

- Refueling activities, including fuel handling and sipping to detect fuel assembly leakage.

- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the primary containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.

- Licensee identification and resolution of problems related to refueling outage activities.

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one refueling outage inspection sample as defined in Inspection Procedure 71111.20-05.

b. Findings

Less Than Adequate Work Planning Resulted in the Release of Two Gas Decay Tanks

Introduction. The inspectors identified a self-revealing Green noncited violation of Technical Specification 5.4.1, "Procedures," after Pacific Gas and Electric inadvertently released the contents of Gas Decay Tanks 2-2 and 2-3 into the auxiliary building on October 11, 2009.

Description. Waste gases from the reactor coolant system, liquid holdup tanks, volume control tank, pressurizer relief tank, and reactor coolant drain tank are compressed and stored in one of three gas decay tanks. Each gas decay tank, located in the auxiliary building basement, has a nominal volume of 775 cubic feet and contains about 48,000 pounds of waste gas at 100 psig. The licensee stores waste gas in the decay tanks for a minimum of 45 days allowing for radioactivity decay prior to atmospheric release through the plant vent stack. The licensee operates the system with one decay tank aligned to "purge" to displace oxygen from plant vessels and piping that contain explosive gases. The radiological consequences of a postulated rupture or ground level release of a gas decay tank is considered a facility design basis accident and is described in FSARU Section 15.5.24, "Environmental Consequences of a Rupture of a Waste Gas Decay Tank."

On October 11, 2009, plant operators inadvertently released the contents of Gas Decay Tanks 2-2 and 2-3 into the auxiliary building while placing equipment clearances. Plant operators had previously aligned Gas Decay Tank 2-2 to purge mode. One group of plant operators was implementing a clearance of the Unit 2 emergency core cooling system per Attachment 9.2, "Auxiliary Building Vent and Drain Alignment Checklist," of Procedure OP A-2: VIII, "Clearing and Draining ECCS Systems for the Core Offload Window," Revision 12. A second group of operators was implementing Clearance 2C15D-10-002, "Core Offload Master." The parallel implementation of both equipment clearances resulted in chemical volume control system Valves 2-109, 2-124, 2-103, and 2-107 to be open at the same time, allowing Gas Decay Tank 2-2 to vent directly into the auxiliary building. The pressure in Gas Decay Tank 2-2 dropped from

70 psig to 15 psig in about 63 minutes. The auxiliary building operator received a low gas header pressure alarm after the purge gas pressure dropped to 15 psig. Per procedure, the operator aligned Gas Decay Tank 2-3 to "purge" mode. As a result, Gas Decay Tank 2-3 was also released into the auxiliary building through the open vent path. The pressure in Gas Decay Tank 2-3 dropped from 37 psig to 15 psig in about 23 minutes. Plant operators stopped the equipment clearance work and identified and secured the open valves. The inspectors concluded that the radiological consequences of the event did not result in a potential for overexposure because the reactor had been shutdown since October 3, 2009. Auxiliary building radiation monitors indicated a slight increase in airborne radiation levels, but did not alarm. No personnel dosimetry alarm limits were reached, and no personnel contaminations occurred.

Analysis. The inspectors concluded that the failure to properly implement the core offload master equipment control clearance was a performance deficiency. The finding is more than minor because the performance deficiency could be reasonably viewed as a precursor to a significant event. The inspectors concluded that the finding was associated with the Barrier Integrity Cornerstone. Using Inspection Manual Chapter 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," the inspectors determined the finding to have very low safety significance because the performance deficiency only represented a degradation of the auxiliary building radiological barrier function. This finding has a crosscutting aspect in the area of human performance associated with the work control component because the licensee did not adequately plan and coordinate the two clearance activities or fully consider the impact of the work on different job activities and the need for the two work groups to maintain interfaces [H.3(b)].

Enforcement. Technical Specification 5.4.1.a, "Procedures," required the licensee to implement and maintain the applicable procedures recommended in Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2. Regulatory Guide 1.33, Appendix A, included equipment control procedures. Equipment Control Procedure OP A-2: VIII, "Clearing and Draining ECCS Systems for the Core Offload Window, Revision 12, Step 2.4.10, required plant operators to review the master clearance for points that may interfere with other work that may be in progress prior to implementation. Contrary to the above, on October 11, 2009, plant operators did not adequately review the master clearance for points that may interfere with other work that may be in progress prior to implementation of Procedure OP A-2: VIII. As a result, Procedure OP A-2:VIII interfered with Clearance 2C15D-10-002, "Core Offload Master," resulting in the unplanned release of two gas decay tanks. Because this finding is of very low safety significance and was entered into the corrective action program as Notification 50273734, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000323/2009005-01, "Less Than Adequate Work Planning Resulted in the Release of Two Gas Decay Tanks."

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the FSARU, procedure requirements, and technical specifications to ensure that the four surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning
- Evaluation of testing impact on the plant
- Acceptance criteria
- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations, root causes, and bases for returning tested systems, structures, and components not meeting the test acceptance criteria were correct
- Reference setting data
- Annunciators and alarms setpoints

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- Unit 2, Penetration 45 containment isolation valve leak testing, October 18, 2009
- Unit 2, Penetration 56 containment isolation valve leak testing, November 1, 2009
- Unit 1, Component Cooling Water Pump 1-3, November 13, 2009
- Unit 2, reactor coolant system water inventory balance, November 15, 2009

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four surveillance testing inspection samples as defined in Inspection Procedure 71111.22-05.

b. Findings

No findings of significance were identified.

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspectors discussed with licensee staff the operability of offsite siren emergency warning systems to determine the adequacy of licensee methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The licensee's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1; FEMA Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants"; and the licensee's current FEMA-approved alert and notification system design report, "Diablo Canyon Power Plant Site-Specific Offsite Radiological Emergency Preparedness Alert and Notification System Quality Assurance Verification Report," December 1984. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.02-05.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors discussed with licensee staff the operability of primary and backup systems for augmenting the on-shift emergency response staff to determine the adequacy of licensee methods for staffing emergency response facilities in accordance with their emergency plan. The inspectors reviewed the documents and references listed in the attachment to this report, to evaluate the licensee's ability to staff the emergency response facilities in accordance with the licensee's emergency plan and the requirements of 10 CFR Part 50, Appendix E. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.03-05.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed summaries of 738 corrective action program documents assigned to the emergency preparedness department and emergency response organization between July 2007 and December 2009, and selected 28 for detailed review against the program requirements. The inspectors evaluated the response to the corrective action requests to determine the licensee's ability to identify, evaluate, and correct problems in accordance with the licensee program requirements, planning standard 10 CFR 50.47(b)(14), and 10 CFR Part 50, Appendix E. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.05-05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on November 19, 2009, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.06-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational and Public Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess licensee personnel's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls. The inspectors used the requirements in 10 CFR Part 20, the technical specifications, and the licensee's procedures required by technical specifications as criteria for determining compliance. During the inspection, the inspectors interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspectors also reviewed activities associated with the reactor head replacement to fulfill the inspection requirements of Inspection Procedure 71007, "Reactor Vessel Head Replacement Inspection." The inspectors performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone
- Controls (surveys, posting, and barricades) of radiation, high radiation, or airborne radioactivity areas
- Radiation work permits, procedures, engineering controls, and air sampler locations
- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms
- Barrier integrity and performance of engineering controls in airborne radioactivity areas
- Adequacy of the licensee's internal dose assessment for any actual internal exposure greater than 50 mrem committed effective dose equivalent
- Corrective action documents related to access controls
- Adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination control during job performance
- Dosimetry placement in high radiation work areas with significant dose rate gradients
- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas
- Controls for special areas that have the potential to become very high radiation areas during certain plant operations
- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of 15 of the required 21 samples as defined in Inspection Procedure 71121.01-05.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee personnel's performance with respect to maintaining individual and collective radiation exposures ALARA. The inspectors used the requirements in 10 CFR Part 20 and the licensee's procedures required by technical specifications as criteria for determining compliance. The inspectors also reviewed activities associated with the reactor head replacement to fulfill the inspection requirements of Inspection Procedure 71007, "Reactor Vessel Head Replacement Inspection." The inspectors interviewed licensee personnel and reviewed the following:

- Current 3-year rolling average collective exposure

- Five work activities from previous work history data which resulted in the highest personnel collective exposures

- Site-specific trends in collective exposures, plant historical data, and source-term measurements

- Site-specific ALARA procedures

- Three work activities of highest exposure significance completed during the last outage

- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements

- Intended versus actual work activity doses and the reasons for any inconsistencies

- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups

- Integration of ALARA requirements into work procedure and radiation work permit (or radiation exposure permit) documents

- Dose rate reduction activities in work planning

- Postjob (work activity) reviews

- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates

- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered

- Exposure tracking system

- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding

- First-line job supervisors' contribution to ensuring work activities are conducted in a dose efficient manner

- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry

- Source-term control strategy or justifications for not pursuing such exposure reduction initiatives

- Specific sources identified by the licensee for exposure reduction actions, priorities established for these actions, and results achieved since the last refueling cycle

- Declared pregnant workers during the current assessment period, monitoring controls, and the exposure results

- Resolution through the corrective action process of problems identified through postjob reviews and postoutage ALARA report critiques

- Corrective action documents related to the ALARA program and follow-up activities, such as initial problem identification, characterization, and tracking

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of 12 of the required samples and 10 of the optional samples as defined in Inspection Procedure 71121.02-05.

b. Findings

Introduction. The inspectors reviewed a Green, self-revealing, noncited violation of Technical Specification 5.4.1(a) for failure to properly plan the disassembly of the Unit 2 reactor head.

Description. During the outage, AREVA was the main contractor associated with the reactor vessel head replacement activities. As described below, AREVA with the licensee's oversight inadequately planned the various maintenance tasks associated with the head replacement. These tasks included maintenance Work Orders 68004363 (disassembly of the old head) and 68003988 (scaffolding activities). Radiation Work Permits 09-2233 and 09-2237 were developed to support work activities, including the above work orders.

Radiation Work Permits 09-2233 and 09-2237 had an initial combined dose estimate of 5.869 rem and 1102 man-hours. However, the job ended with an actual combined dose of 17.378 rem and 1882 man-hours, which exceeded the initial dose estimate by 296 percent. The overarching reason for exceeding the original dose estimate was improper planning and control of the maintenance, which increased the man-hours to complete the task by 170 percent.

Two examples of inadequate planning and control for the task were insufficient communication between the licensee and its vendors relative to design plans and excessive scaffold building and modification activities. An unplanned 2.071 rem was expended for cutting the wrong part length conduits due to difficulties with fitting the structural support plate used in the AREVA lifting device for removal of the old reactor vessel closure head. This was a result of AREVA using a structural support plate that was not specifically designed for the old reactor vessel head. There were numerous occurrences in which scaffolding had to be disassembled and reassembled because job sequence was not properly planned or did not fit the current plant conditions. It was determined that the dose expended just for the purpose of scaffolding modifications was 4.821 rem and 846 man-hours. The licensee met with AREVA to determine appropriate recovery measures.

Analysis. The failure to properly plan maintenance activities is a performance deficiency. This finding is greater than minor because it affected the Occupational Radiation Safety cornerstone attribute of Program and Process in that the inadequate ALARA planning caused increased collective radiation dose for the job activity to exceed 5 person-rem and the planned dose by more than 50 percent. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined this finding to be of very low safety significance because although it involved ALARA planning and controls, the licensee's latest rolling three-year average does not exceed 135 person-rem per unit. Furthermore, the finding had an associated human performance cross-cutting aspect in the work control component because the licensee did not fully incorporate job site conditions, plant structures, systems, and components, as well as human-system interface and the need for planned contingencies to maintain doses ALARA [H.3(a)].

Enforcement. Technical Specification 5.4.1(a) requires written procedures be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, February 1978. Section 9, "Procedures for Performing Maintenance," of Appendix A to Regulatory Guide 1.33 requires, in part, that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures. Contrary to this requirement, during Refueling Outage 15, numerous maintenance activities associated with work inside containment, including Work Orders 68004363 (disassembly of the old head) and 68003988 (scaffolding activities) were not properly planned, thereby requiring those maintenance activities to be changed and/or repeated, which resulted in increased radiation exposure. Because this violation is of very low safety significance and was entered into the corrective action program as Notification 50275107, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000323/2009005-02; "Failure to Properly Plan a Maintenance Activity."

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the third quarter 2009 performance indicators for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, "Performance Indicator Program."

This review was performed as part of the inspectors' normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Specific Activity (BI01)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity performance indicator for Diablo Canyon Units 1 and 2 for the period from the third quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5. The inspectors reviewed the licensee's reactor coolant system chemistry samples, technical specification requirements, issue reports, event reports, and NRC integrated inspection reports for the period from October 1, 2008 through September 30, 2009 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two reactor coolant system specific activity samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.3 Reactor Coolant System Leakage (BI02)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage performance indicator for Diablo Canyon Units 1 and 2 for the period from the third quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5. The inspectors reviewed the licensee's operator logs, reactor coolant system leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of October 1, 2008 through September 30, 2009 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two reactor coolant system leakage samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.4 Drill/Exercise Performance (EP01)

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill and Exercise Performance, performance indicator for the period from the fourth quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the Nuclear Energy Institute guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator; assessments of performance indicator opportunities during predesignated control room simulator training sessions, performance during the 2008 biennial exercise, and performance during other drills. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of the drill/exercise performance sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.5 Emergency Response Organization Drill Participation (EP02)

a. Inspection Scope

The inspectors sampled licensee submittals for the Emergency Response Organization Drill Participation performance indicator for the period from the fourth quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the Nuclear Energy Institute guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator, rosters of personnel assigned to key emergency response organization positions, and exercise participation records. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of the emergency response organization drill participation sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.6 Alert and Notification System (EP03)

a. Inspection Scope

The inspectors sampled licensee submittals for the Alert and Notification System performance indicator for the period from the fourth quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the Nuclear Energy Institute guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator and the results of periodic alert notification system operability tests. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of the alert and notification system sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.7 Occupational Exposure Control Effectiveness (OR01)

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences performance indicator for the period from the fourth quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's assessment of the performance indicator for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's performance indicator data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review, and the results of those reviews. The inspectors independently reviewed electronic dosimetry dose rate and accumulated dose alarm and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas.

These activities constitute completion of the occupational radiological occurrences sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.8 Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual Radiological Effluent Occurrences (PR01)

a. Inspection Scope

The inspectors sampled licensee submittals for the Radiological Effluent Technical Specifications/Offsite Dose Calculation Manual Radiological Effluent Occurrences performance indicator for the period from the fourth quarter 2008 through the third quarter 2009. To determine the accuracy of the performance indicator data reported during those periods, performance indicator definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's issue report database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose.

These activities constitute completion of the radiological effluent technical specifications/offsite dose calculation manual radiological effluent occurrences sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors reviewed attributes that included: the complete and accurate identification of the problem; the timely correction, commensurate with the safety significance; the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews; and the classification, prioritization, focus, and timeliness of corrective actions. Minor issues entered into the licensee's corrective action program because of the inspectors' observations are included in the attached list of documents reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. The inspectors accomplished this through review of the station's daily corrective action documents.

The inspectors performed these daily reviews as part of their daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors focused their review on repetitive equipment issues, but also considered the results of daily corrective action item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors nominally considered the 6-month period of July 1, 2009, through December 31, 2009, although some examples expanded beyond those dates where the scope of the trend warranted.

The inspectors also included issues documented outside the normal corrective action program in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenge lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and maintenance rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's corrective action program trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy. Specific documents reviewed are listed in the attachment.

These activities constitute a single semi-annual trend inspection sample.

b. Findings and Observations

Adverse Trend in Problem Evaluation

The inspectors concluded that the adverse trend associated with the thoroughness of Pacific Gas and Electric's problem evaluation, originally identified by the NRC in September 2008 (described in Section 4OA2 of Inspection Report 05000275/2008005), continued through 2009. This trend included eleven NRC documented findings with problem evaluation crosscutting aspects. In October 2008, Pacific Gas and Electric entered this adverse trend into the corrective action program as Notification 50081161, "Loss of Margin in NRC PI&R Crosscutting." In November 2008, the licensee completed a common cause analysis of the trend and concluded:

- The station is not interpreting regulatory requirements consistent with the current NRC interpretations, and
- The station is not reviewing NCVs issued at other plants as applicable to Diablo Canyon.

The licensee's corrective actions included enhanced guidance for plant staff interactions with the NRC with the addition of "lessons learned" to the engineering training program. The NRC concluded that the licensee's causal analysis was narrowly focused on the NRC rather than addressing the broader issue of organizational barriers to effective problem evaluation.

The inspectors concluded that most of the NRC identified examples of less than adequate problem evaluation during the first two quarters of 2009 were related to a poor understating of the plant design/licensing basis or implementation of administrative regulatory programs (described in Section 4OA2 of Inspection Report 05000275/2009003). From an analysis of this adverse trend, the inspectors concluded that a cultural barrier to understanding regulatory processes, including the application of plant design/licensing basis to plant operations, existed at Diablo Canyon.

In April 2009, Pacific Gas and Electric completed a root cause analysis of the trend, “Inadequate Thoroughness when Evaluating Problems” (Notification 60014096). The licensee concluded that “Diablo Canyon evaluations were focused on meeting historical compliance based on licensing and design positions or relied on previous evaluations.” The licensee concluded that contributing to this trend was that “the complex Diablo Canyon licensing basis is not well understood or communicated.” Pacific Gas and Electric implemented two corrective actions to address inadequate problem evaluation:

- Establish standards for documentation of evaluations
- Implement evaluation training

The inspectors again concluded that the licensee’s corrective actions were not adequately comprehensive to address the underlying barriers to effective problem evaluation.

In October 2009, the licensee completed an apparent cause evaluation of five NRC traditional enforcement violations issued during the past twelve months. The licensee’s corrective actions included establishment of a 10 CFR 50.59 evaluation quality review board and enhanced 10 CFR 50.59 training. The inspectors again concluded these corrective actions were less than adequate to address the underlying issues. For example, the NRC identified three examples of less than adequate current 10 CFR 50.59 evaluations during 2009.

- Failure to evaluate a change to the facility as described in the FSARU associated with 500 kV Offsite Power Source (NCV 05000275;323/2009003-06): The inspectors concluded that the issue was a result of the licensee’s failure to recognize and apply industry screening and evaluation criteria.
- Changes to the 230 kV offsite power system (described in Section 4OA5.7 of this report). The inspectors concluded that the licensee performed a less than adequate 10 CFR 50.59 re-evaluation due to a lack of understanding of the NRC approval and licensee amendment process (Notification 50248299).
- Less than adequate change evaluation to the facility as Described in the Final Safety Analysis Report Update (described in Section 4OA5.6 of this report) . The inspectors concluded that the licensee did a less than adequate evaluation due to a lack of understanding of the use of regulatory guides in the licensing basis.

Common to all three recent examples was a high level of senior plant management engagement in the decision-making processes associated with the evaluations. The inspectors also identified a number of less than adequate latent evaluations. Recent examples include:

- Changes to the steam generator tube rupture accident analysis without obtaining prior NRC approval (described in Section 4OA2 of this report)

- Changes to the offsite power loading analysis without obtaining prior NRC approval (described in Section 4OA5 of this report)

The inspectors concluded that the licensee's corrective actions associated with October 2009 apparent cause evaluation were insufficient to identify and correct past inadequate evaluations that have led to incorrect changes in the plant licensing basis.

.4 Selected Issue Follow-up Inspection

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized corrective action items documenting:

- Notification 50281724, "NSAL 09-8: Presence of Vapor in ECCS/RHR," November 5, 2009

- Notification 50270786, failure to update the Final Safety Analysis Report Update with current accident analysis, September 28, 2009

These activities constitute completion of two in-depth problem identification and resolution samples as defined in Inspection Procedure 71152-05.

b. Findings

Inadequate 50.59 Evaluation for Steam Generator Tube Rupture

Introduction. The inspectors identified a Severity Level IV noncited violation of 10 CFR 50.59 after Pacific Gas and Electric failed to perform an adequate evaluation of a change to the facility as described in the Final Safety Analysis Report Update. This change resulted in a departure from the method of evaluation used for the steam generator tube rupture accident described in the FSARU and required NRC approval prior to implementation.

Description. Pacific Gas and Electric completed and submitted to the NRC for approval the steam generator tube rupture analysis as described in WCAP-11723, "LOFTTR2 Analysis for a Steam Generator Tube Rupture for the Diablo Canyon Power Plant Units 1 and 2" on April 29, 1988. The NRC approved the accident analysis on April 3, 1991. The NRC basis of approval of the accident analysis, as described in the safety evaluation report, was the generic approval of the methodology described in WCAP-10698-P-A,"SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," dated August 1987 which included four time critical operator actions, each assumed to occur after the first 10 minutes following the accident. The licensee subsequently identified that auxiliary feedwater and steam generator power-operated relief valve flow rates assumed in WCAP-11723 were non-conservative. To address the non-conforming condition, Pacific Gas and Electric revised WCAP-11723 input assumptions to include a new time critical operator action to terminate turbine-driven auxiliary feedwater flow within 5.54 minutes after the reactor trip and credit motor driven auxiliary feedwater automatic level control to the ruptured steam generator. The licensee screened these changes under 10 CFR 50.59 and concluded a safety evaluation was not required on December 2, 1992.

The inspectors concluded that the addition of a new operator action required a safety evaluation and prior NRC approval under the 10 CFR 50.59 rule in effect at the time. Prior NRC approval was required because the new time critical operator action reduced the margin to safety to the basis of Technical Specification 3.7.4, “10 Percent Atmospheric Dump Valves.” The basis for Technical Specification 3.7.4 included recovery from a steam generator tube rupture event and credited operator actions to terminate the primary to secondary break flow into the ruptured steam generator. These timed operator actions were required by the NRC to limit offsite dose consequences during the accident. The licensee’s incorporation of operator action prior to 10 minutes in the accident analysis reduced the margin to safety established in the NRC safety evaluation report approving the method and conclusions of WCAP-11723.

The inspectors also concluded that the licensee was required to perform an evaluation of the change using the 10 CFR 50.59 rule currently in effect. Regulatory Guide 1.187, “Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments,” stated that the methods described in NEI 96-07, “Guidelines for 10 CFR 50.59 Evaluations,” Revision 1, are acceptable to the NRC staff for complying with the provisions of 10 CFR 50.59. NEI 96-07, Section 4.3.8, “Does the Activity Result in a Departure from a Method of Evaluation Described in the Final Safety Analysis Report Update Used in Establishing the Design Bases or in the Safety Analyses?,” stated that licensees can make changes to elements of a methodology without first obtaining a license amendment if the results are essentially the same as, or more conservative than, previous results. The safety evaluation report stated NRC approval of the steam generator accident analysis was based on four time critical operator actions. The analysis credited termination of turbine-drive auxiliary feedwater flow 12 minutes after the reactor trip. The licensee’s change for this operator action to 5.54 minutes was a non-conservative change and required prior NRC approval under the current rule.

The performance deficiency, a less than adequate 50.59 evaluation, was the result of a latent issue. However, the licensee had the following reasonable opportunities to identify the problem:

- In October 2008, during the licensee’s review of the revised steam generator tube rupture accident performed in support of the steam generator replacement

- In May 2009, during the licensee’s evaluation of Notification 50237461, “Time Critical Operator Actions Controls,” Task 1, “Evaluate SGTR Simulator Scenario,” and

- In August 2009, during the licensee’s follow up of NCV 05000275;323/2009004-04, “Failure to Update the Final Safety Analysis Report Update with Current Accident Analysis.”

The inspectors concluded that plant programs, processes or organizations have not changed such that the problem would not reasonably occur today.

Analysis. The failure of Pacific Gas and Electric to perform a 10 CFR 50.59 evaluation of the revision to WCAP-11723 was a performance deficiency. The inspectors evaluated this issue using the traditional enforcement process, including NRC Enforcement Policy, Supplement I, Reactor Operations, because the performance deficiency had the potential for impacting the NRC’s ability to perform its regulatory function. The inspectors concluded that the issue was more than minor because of reasonable likelihood the change to the facility would require Commission review and approval prior to implementation. The inspectors also evaluated the significance of this issue under the Significance Determination Process using Inspection Manual Chapter 0609.04, "Phase 1-Initial Screening and Characterization of Findings." The finding affected the Mitigating Systems Cornerstone because the change described the operator actions required to mitigate steam generator tube rupture accident. The inspectors concluded the finding screened Green because the finding was a design deficiency that did not result in the loss of operability or functionality. The inspectors concluded that the violation was a Severity Level IV because the issue screened Green under the Significance Determination Process. The inspectors concluded that this finding had a crosscutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee did not thoroughly evaluate the steam generator tube rupture analysis such that the resolutions addressed causes and extent of condition [P.1(c)].

Enforcement. Title 10 CFR 50.59, "Changes, Tests and Experiments," stated that a licensee may make changes in the facility as described in the final safety analysis report without obtaining a license amendment if the change does not result in a departure from a method of evaluation described in the FSARU used in establishing the design bases or in the safety analyses. Contrary to the above, on December 2, 1992, Pacific Gas and Electric made changes to the facility as described in the final safety analysis report without obtaining a license amendment that resulted in a departure from a method of evaluation described in the Final Safety Analysis Report used in establishing the design bases or in the safety analyses. Specifically, Pacific Gas and Electric added a time critical operator action to steam generator tube rupture accident analysis to terminate turbine-driven auxiliary feedwater flow in 5.54 minutes. Because this finding is of very low safety significance and was entered into the corrective action program as Notification 50270786, this violation is being treated as a noncited violation in accordance with Section VI.A.1 of the Enforcement Policy: NCV 05000275/2009005-02, NCV 05000323/2009005-03 "Inadequate 50.59 Evaluation for Steam Generator Tube Rupture Analysis."

4OA3 Event Followup (71153)

.1 Inspection for Reactivity Management Issues

a. Inspection Scope

In response to the use of an unapproved reactivity management plan during a planned shutdown on August 13, 2009, an inspection was conducted October 1, 2009 through October 5, 2009. The inspectors reviewed reactivity management procedures, corrective action documents regarding reactivity management issues and operations administrative procedures. In addition, the inspectors interviewed licensed operators, observed a reactor shutdown from the control room and identified any potential safety conscious work environment concerns.

The documents reviewed during this inspection are listed in the attachment.

b. Findings and Observations

A Green licensee-identified noncited violation was identified for failure to correctly implement Section 5.4.5 of safety-related Procedure OP1.ID3, "Reactivity Management Program." See Section 4OA7 for details.

After review, the inspectors concluded the use of an unapproved reactivity management plan was an isolated event and acceptable corrective actions have been implemented. Observations of reactivity management and conduct of operations during the planned shutdown on October 3, 2009, were consistent with approved procedures. No safety conscious work environment concerns were identified.

.2 (Closed) Licensee Event Report 2-2009-001-00 Technical Specification 3.0.3 One Hour Exceeded Due to Failure of Group Step Counters

On March 17, 2009, plant operators exceeded the one-hour time allowed by Technical Specification 3.0.3, after the failure of the second Unit 2 Bank "B" group step counter digital display, a condition not allowed by Technical Specification 3.1.7, "Rod Position Indication." The licensee concluded that the cause of the event was inappropriate maintenance schedule and priority to replace the group demand counter batteries prior to failure. The inspectors reviewed this issue during the second quarter of 2009 and documented an NRC-identified violation in Section 4OA2 of Inspection Report 05000275/2009003; 05000323/2009003. This Licensee Event Report is closed.

.3 (Closed) Licensee Event Report 2-2009-002-00 Technical Specification 3.7.1 Violation Due to Cracked Valve Spring

On August 26, 2009, Unit 2 plant operators declared the main steam safety valve (MSSV) RV-224 inoperable in accordance with Technical Specification 3.7.1, "Main Steam Safety Valves" and reduced reactor power to approximately 80 percent power. The valve was declared inoperable due to a cracked spring. Plant operators took immediate corrective actions and gagged the Main Steam Safety Valves to preclude inappropriate opening during power operation. The licensee also inspected the other safety valves to ensure similar conditions did not exist. On September 17, 2009, the licensee received an exigent technical specification amendment to return Unit 2 to full power for the remainder of the operating cycle. The safety valve was subsequently repaired during the following refueling outage. The inspectors did not identify any violations of NRC requirements. This Licensee Event Report is closed.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors performed observations of security force personnel and activities to ensure that the activities were consistent with Pacific Gas and Company's security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Temporary Instruction 2515/172, "Reactor Coolant System Dissimilar Butt Welds"(Closed)

Temporary Instruction 2515/172 was previously performed at Diablo Canyon Unit 1, in March 2009, and Unit 2, in March 2008. The results of the previous inspections are documented in Inspection Reports 05000275/2009002 and 05000323/2008002, respectively.

Following guidance of Temporary Instruction 2515/172, the inspectors have completed all NRC activities associated with this Temporary Instruction.

03.01.1 Licensee's Implementation of the MRP-139 Baseline Inspection

a. Baseline inspections on the dissimilar metal butt welds were performed for Diablo Canyon Unit 1 in November 2005 and for Unit 2 in February 2008. The inspectors reviewed the baseline inspections of Unit 1 and verified that the inspections were completed in accordance of MRP-139.

b. At the time of this inspection, the licensee has not deviated from the requirements of MRP-139 and all future examinations are scheduled in accordance with MRP-139.

03.02 Volumetric Examinations

a. During the current Unit 2 refueling outage, the licensee performed volumetric examinations of the mitigated pressurizer safety, surge line, and relief nozzles in accordance with MRP-139 and Relief Request REP-1 U2, "The Application of Weld Overlay on Dissimilar Metal Welds of Pressurizer Nozzles," Revision 1. No relevant conditions or indication were identified during the ultrasonic examinations.
b. Inspectors directly observed and/or reviewed records of NDE performed on pressurizer weld overlays. This effort is documented in Section 1R08 of this inspection report. For each weld overlay inspected the licensee submitted and received NRC approval by letter dated February 6, 2008, for the use of Relief Request REP-1 U2, "The Application of Weld Overlay on Dissimilar Metal Welds of Pressurizer Nozzles," Revision 1. Inspection coverage met requirements of MRP-139. No relevant conditions were identified.

c. The certification records of ultrasonic examination personnel used in the examination of the hot leg and cold leg reactor vessel nozzles and the mitigated pressurizer DMBWs were reviewed. All personnel records showed that they were qualified under the EPRI Performance Demonstration Initiative.

d. No deficiencies were identified during the nondestructive examinations.

03.03.1 Weld Overlays

No weld overlays were completed during this outage. Weld overlays were completed in the previous Unit 2 outage, March 2008. No relevant conditions were identified.

03.03.2 Mechanical Stress Improvement

This item is not applicable because mechanical stress improvement was not employed at Diablo Canyon.

03.04 Inservice Inspection Program

Hot leg and cold leg nozzles in both units are appropriately categorized as "D" and "E", respectively. Future ultrasonic inspection plans for both hot leg and cold leg welds are consistent with MRP-139, Category "D" and "E" requirements. These future inspections are included in the plants inservice inspection program and reoccurring work requests have been established for these welds. The hot leg inspections will next occur in fall 2010 for Unit 1 and spring 2011 for Unit 2. The cold leg inspections will next occur in either fall 2010 or spring 2012 for Unit 1 and spring 2011 or fall 2012 for Unit 2. The Unit 2 pressurizer weld overlays are appropriately categorized as "F", in accordance with MRP-139. However, inspection for the pressurizer weld overlays is governed by the 2004 edition with 2005 and 2006 addenda, of ASME Section XI, Appendix Q. Inspection using Appendix Q were required by Relief Request REP-1 U2, "The Application of Weld Overlay on Dissimilar Metal Welds of Pressurizer Nozzles," Revision 1. The inspection requirements of Appendix Q are more conservative than the requirements of MRP-139 guidance. Ultrasonic examinations of the pressurizer nozzles were completed during this outage. No relevant indications were identified.

.3 Reactor Vessel Head Replacement Inspection (71007)

Design and Planning Inspections

a. Inspection Scope

The inspectors used the guidance in Inspection Procedure 71007 to perform the following reactor vessel head design and planning inspection activities.

Engineering and Technical Support

Inspections were conducted by resident and regional office-based specialist inspectors to review engineering and technical support activities performed prior to, and during, the reactor vessel head replacement outage. This review verified that selected design changes and modifications to structures, systems, and components described in the

FSARU for transporting the new and old reactor vessel heads were reviewed in accordance with 10 CFR 50.59. Additionally, key design aspects and modifications associated with the reactor vessel head replacement were also reviewed. Finally, the inspectors determined if the licensee had confirmed that the existing reactor vessel head conformed to design requirements and that there were no fabrication deviations from design requirements.

Lifting and Rigging

The inspectors reviewed engineering design, modification, and analysis associated with reactor vessel head lifting and rigging activities. This included: (1) crane and rigging equipment; (2) reactor vessel head component drop analysis; (3) safe load paths; and (4) load lay-down areas.

Radiation Protection

The review of radiation protection program controls, planning, and preparation in: (1) ALARA planning; (2) dose estimates and tracking; (3) exposure and contamination controls; (4) radioactive material management; (5) radiological work plans and controls; (6) emergency contingencies; and (7) project staffing and training plans. This review was performed as part of the baseline inspections conducted during the 2R15 outage and additional information is documented in Section 2OS2 of this report.

Reactor Vessel Head Fabrication Inspections at Licensee Facility

The inspectors used the guidance in Inspection Procedure 71007 to perform the following reactor vessel head fabrication inspection activities.

Heat Treatment

The inspectors verified that the material heat treatment used to enhance the mechanical properties of the reactor vessel head material carbon, low alloy, and high alloy chromium steels is conducted per ASME Code and approved vendor procedures consistent with the applicable ASME Code, Section III requirements. Also, inspections were performed to verify that adequate heat treatment procedures were available to assure that the following requirements were met: (1) furnace atmosphere; (2) furnace temperature distribution and calibration of measuring and recording devices; (3) thermocouple installation; (4) heating and cooling rates; (5) quenching methods; and (6) record and documentation requirements.

Nondestructive Examination (NDE)

Inspections were conducted to ensure the manufacturing control plan included provisions for monitoring NDE to ascertain that the NDE was performed in accordance with applicable code, material specification, and contract requirements.

Welding

The inspectors reviewed the documentation for the weld overlay welding operations that established a layer of stainless steel cladding on the inside of the reactor vessel head to determine if it was accomplished per design. The inspectors also selected a sample of dome-to-flange and CRDM flange-to-nozzle welds and reviewed the following items:

(1) certified mill test reports of the dome, flange, weld material rods, and CRDM nozzles; (2) certified mill test reports for the welding material for the reactor vessel head cladding; (3) cladding weld records, weld rod material control requisitions, traceability of weld material rods, weld procedure qualification, welder qualifications, and nonconformance reports; (4) CRDM nozzle cladding welding inspection records, weld rod material control requisitions, traceability of weld material rods, weld procedure qualification, welder qualifications, and nonconformance reports; (5) CRDM to nozzle welding and welds inspection records, weld rod material control requisitions, traceability of weld material rods, weld procedure qualification, welder qualifications, and non-conformance reports; and (6) NDE procedures, NDE records of the welds, NDE personnel qualifications, and certification of the NDE solvents.

Procedures

Inspections were completed to ensure that repair procedures had been established and that these procedures were consistent with applicable ASME Code, material specification, and contract requirements by verifying: (1) repair welding was conducted in accordance with procedures qualified to Section IX of the ASME Code; (2) all welders had been qualified in accordance with Section IX of the ASME Code; (3) records of the repair were maintained; and (4) that requirements had been established for the preparation of certified material test reports and that the records of all required examinations and tests were traceable to the procedures to which they were performed.

Code Reconciliation

The inspectors reviewed the required documentation, supplemental examinations, analysis, and ASME Code documentation reconciliation to ensure that the original ASME Code N-Stamp remains valid, and that the replacement head complies with appropriate NRC rules and industry requirements. The inspectors also ensured that the design specification was reconciled and a design report was prepared for the reconciliation of the replacement head, verifying that they were certified by professional engineers competent in ASME Code requirements.

Quality Assurance Program

Inspections were conducted to ensure that: (1) machining was carried out under a controlled system of operation; (2) a drawing/document control system was in use in the manufacturing process; and (3) that part identification and traceability was maintained throughout processing and was consistent with the manufacturer’s quality assurance program. In addition, the inspectors ensured that only the specified drawing and document revisions were available on the shop floor and were being used for fabrication, machining, and inspection.

Compliance Inspection

The inspectors verified that the original ASME Code, Section III, data packages for the replacement reactor vessel head were supplemented by documents included in the ASME Code, Section XI, (pre-service inspection) data packages; examined selected manufacturing and inspection records of the finished machined reactor vessel head; and verified compliance with applicable documentation requirements.

b. Findings

Less than Adequate Replacement Reactor Head Modification Design Control

Introduction. The inspectors identified a Green noncited violation of 10 CFR, Part 50, Appendix B, Criteria III, "Design Control," associated with two examples of less than adequate ASME Code mechanical stress calculations for the Unit 2 replacement reactor head modification. In both examples, the replacement head contractor, AREVA NP Incorporated, used inappropriate critical seismic damping values in the design of reactor head and components.

Description. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code Section III, required the replacement reactor head to be designed not to fail during the postulated earthquakes to be included in the plant design basis. The designer considers the amount of mechanical stress that components may be exposed to as a result of normal operation and faulted conditions when specifying critical parameters such as type of material, wall thickness, and fastener size. During an earthquake, welded or bolted components respond differently to the applied energy. Seismic damping is a design input used to calculate how this energy is distributed as the component responds to dynamic excitation. Damping values are directly applied to the design calculations to determine the amount of mechanical stress the component may be exposed. The designer will verify that the component stress is within ASME Code allowable. The damping values used in nuclear designs are specified in the plant design basis.

The replacement reactor head modification included a complete redesign of the integrated head assembly. The head assembly is a steel structure that provides support for the control rod drive cooling and seismic components, the missile shield structure, cooling fans head lifting rig and cable runs. The head assembly is about 43 feet tall with more than 10,000 parts assembled by bolted or welded connections. During an earthquake, the integrated head assembly transmits the seismically induced loads to the reactor cavity wall by six pinned tie rods. Design Calculation 38-9039840-001, "IHA Damping," June 14, 2007, incorporated a critical damping value of 7 percent when demonstrating that the head assembly met ASME Code allowable stress. The inspectors identified that the 7 percent damping was specific for bolted steel with bearing connections. However, the head assembly used a combination of bolted and welded connections. A damping of 4 percent should have been used for the welded connections. Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants," Revision 1, specified that the lowest specified damping value be used for steel structures with a combination of different connections types, or as an alternative, use a weighed average based on the number of each type present in the structure. The contractor re-evaluated the integrated head assembly seismic stress (Calculation 51-9125626-000, October 28, 2009) using the method described in Regulatory Guide 1.61 and concluded the structure would meet ASME Code allowable stress during postulated earthquakes.

The replacement reactor head included new control rod drive mechanism housings. The new housings provide space for withdrawn control rods. These housings are welded to the top of the replacement reactor head and are part of the reactor coolant pressure boundary. ASME Code required a minimum housing wall thickness based on calculated primary membrane and bending stress intensities that may result from normal operation and faulted conditions, including design basis earthquakes. Calculation 33-9069445-001, “Control Rod Drive Mechanism Pressure Housing Assembly Unit 1 and 2 Appurtenances ASME III Class 1 – Design Report,” July 30, 2008, used a damping value of 5 percent when demonstrating that ASME Code was met. The inspectors identified that the FSARU, Section 3.7.1.3, “Critical Damping Values,” specified 1 percent damping for the design and double design basis earthquakes and 4 percent damping for the Hosgri earthquake for Class 1 welded structural steel assemblies. The replacement head contractor was not able to demonstrate that the new housings would meet the ASME Code allowable stress using the damping values from the FSARU. The contractor subsequently recalculated component stress, Calculation 6 CS 20237, “Analysis of the Impact of Reduced Damping factor on the Results of the Design Report,” November 4, 2009) using 3 percent and 4 percent damping for the design basis and double design basis earthquakes (from Regulatory Guide 1.61, Revision 1) and 4 percent damping for Hosgri earthquake. The contractor also changed the method for determining the seismic response spectra from the time history method, specified in the FSARU Section 3.7.1.2, to the response spectra method. The use of the revised methodology was also provided by Regulatory Guide 1.61, Revision 1.

Analysis. The inspectors concluded that the failure to implement the damping values specified in the plant design basis in the replacement head modification was a performance deficiency. The finding is more than minor because the performance deficiency is associated with the Initiating Events Cornerstone design control attribute and adversely affected the cornerstone objective to limit the likelihood of loss of a coolant accident during a seismic event. Using Inspection Manual Chapter 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” the inspectors determined the finding to have very low safety significance because assuming worst case degradation, the finding would not result in exceeding the Technical Specification limit for reactor coolant system leakage nor have a likely affected other mitigation systems resulting in a total loss of their safety function. This finding has a crosscutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee did not provide adequate contractor oversight to identify the use of improper damping values with a low threshold for identifying issues during design reviews [P.1(a)].

Enforcement. Title 10 CFR 50, Appendix B, Criteria III, “Design Control,” required the licensee to implement measures to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions. FSARU Section 3.7.1.3, “Critical Damping Values,” established the seismic damping values to be used in the design of Class 1 components. Contrary to the above, the licensee failed to assure that design basis seismic damping values were correctly translated into specifications Calculation 38-9039840-001, for the integrated head assembly, and Calculation 33-9069445-001 for the control rod drive mechanism housings. Because this finding is of very low safety significance and was entered into the corrective action program as Notifications 50276107 and 50276288, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000323/2009005-04, “Less than Adequate Replacement Reactor Head Modification Design Control.”

.4 Reactor Vessel Head Removal and Replacement Inspections

a. Inspection Scope

The inspectors used the guidance in Inspection Procedure 71007 to perform the following reactor vessel head removal and replacement inspection activities:

Lifting and Rigging

The inspectors reviewed preparations and procedures for rigging and heavy lifting including crane and rigging inspections, testing, equipment modifications, laydown area preparations, and training for the following activities:

- Area preparation for the outside systems
- Lattice boom crawler crane assembly, disassembly, and operation
- Hydraulic gantry lift system
- Outside bridge and trolley transfer system
- Elevated cantilevered handling device installation and use
- Reactor vessel head lift rig and polar crane
- Downender/upender fixture
- Old reactor vessel head removal
- New reactor vessel head placement
- Transport of old reactor vessel head to storage location

Major Structural Modifications

The inspectors observed that there were no major structural modifications that were made to facilitate reactor vessel head replacement.

Containment Access and Integrity

The inspectors observed there were no modifications to the existing containment access structure or integrity to allow for the reactor vessel head to be removed and installed. The new and old reactor vessel head were moved in and out of containment using the existing equipment hatch.

Outage Operating Conditions

The inspectors reviewed and observed the establishment of operating conditions including: (1) refueling; (2) RCS draindown; (3) system isolation; (4) safety tagging; (5) radiation protection controls; (6) controls for excluding foreign materials in the reactor vessel; (7) verification of the suitability of reinstalled (reused) components for use; and

(8) the installation, use, and removal of temporary services. Section 1R20 of this report documents additional activities that were performed during the outage.

Storage of Removed Reactor Vessel Head

The inspectors reviewed the radiological safety plans and observed the transport, storage, and radiological surveys of the old reactor vessel head to its onsite storage location. This review was performed as part of the baseline inspections conducted during the 2R15 outage and additional information is documented in Section 2OS2 of this report.

b. Findings

No findings of significance were identified.

.5 Post-installation Verification and Testing Inspections

a. Inspection Scope

The inspectors used the guidance in Inspection Procedure 71007 to perform the following post-installation verification and testing inspection activities. Selective inspections were performed of the following areas: (1) containment testing; (2) licensee's post-installation inspections and verifications program and its implementation; (3) RCS leakage testing and review of test results; (4) procedures required for equipment performance testing to confirm the design and to establish baseline measurements; and (5) preservice inspection of new welds.

b. Findings

No findings of significance were identified.

.6 Review of Identification and Resolution of Problems Associated (71007 and 71152)

a. Inspection Scope

The inspectors used the guidance in Inspection Procedures 71007 and 711152 to review items entered in the licensee's corrective action program associated with the replacement reactor head modification. This sample included an in-depth review of the licensee's extent of condition and review of Notification 5028488, Control Rod Damping Values.

b. Findings

Less than Adequate Change Evaluation to the Facility as Described in the Final Safety Analysis Report Update

Introduction. The inspectors identified a Severity Level IV violation of 10 CFR 50.59 after the licensee failed to perform an adequate evaluation to demonstrate that prior NRC approval was not required before making changes to the facility as described in the FSARU. On November 5, 2009, the licensee changed the critical seismic damping values used in the replacement reactor head modification. These changes resulted in a departure from a method of evaluation described in the FSARU establishing the facility design bases.

Description. On November 5, 2009, Pacific Gas and Electric incorporated new critical damping values into integrated head assembly and control rod drive housing design without performing an adequate 10 CFR 50.59 evaluation. In October 2009, the inspectors identified that the replacement reactor head contractor used incorrect damping values in the replacement head design (described in Section 4OA5.3 of this report). The contractor was unable to demonstrate that the design met ASME Code using the damping values specified in the plant design basis. The licensee's corrective actions included a recalculation of component stress using new seismic damping factors and methods included in Regulatory Guide 1.61, Revision 1. Table 1 compares the FSARU damping values with the new values used in the replacement reactor head recalculation.

Table 1
Percent Seismic Damping

Structures, Systems, and Components	Design Earthquake		Double Design Earthquake		Hosgri Earthquake	
	FSAR[1]	New	FSAR[1]	New	FSAR[1]	New
Welded Structural Steel Assembles	1.0	3.0	1.0	4.0	4.0	4.0
Vital Piping Systems	0.5	3.0	0.5	4.0	3.0	4.0
Bolted Steel Assemblies	2.0	5.0	2.0	7.0	7.0	7.0

Note: 1 – Section 3.7.1.3, "Critical Damping Values," specific for the design of Class 1 safety systems and components

The licensee was permitted to make changes to the facility as described in the FSARU without prior NRC approval, provided that these changes did not result in a departure from a method of evaluation described in the FSARU and used in establishing the plant design bases. Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments," stated that the methods described in NEI 96-07, "Guidelines for 10 CFR 50.59 Evaluations," Revision 1, are acceptable to the NRC staff for complying with the provisions of 10 CFR 50.59. NEI 96-07, Section 4.3.8, "Does the Activity Result in a Departure from a Method of Evaluation Described in the Final Safety Analysis Report Update Used in Establishing the Design Bases or in the Safety Analyses?," stated that licensees can make changes to elements of a methodology without first obtaining a license amendment if the results are essentially the same as, or more conservative than, previous results. The inspectors concluded that the change, an increase in seismic damping values used in Class 1 component design, resulted in a less conservative result. Use of the FSARU specified damping values would not have demonstrated that the integrated head assembly and control rod drive housings would withstand a postulated design basis earthquake. NEI 96-07 stated that gaining margin by changing one or more elements of a method of evaluation is considered to be a non-conservative change and a departure from a method of evaluation for purposes of 10 CFR 50.59. NEI 96-07 stated that such departures required NRC approval before the revised method can be used.

The Pacific Gas and Electric 50.59 evaluation for the replacement reactor head, LIBE 2009-021, “Integrated Head Assembly,“ November 5, 2009, stated:

> 1) *“an increase in the DDE damping levels for the CRDM seismic analysis from 3 percent to 4 percent – this is acceptable because the 4 percent damping for DDE is approved by the NRC via RG 1.61 for piping systems and application of this category to CRDMs is conservative.”*
>
> 2) *“the proposed activity does not result in a departure from a method of evaluation described in the FSARU per NEI 96-07”*

The new methodology and damping values used by the licensee was consistent with Regulatory Guide 1.61, “Damping Values for Seismic Design of Nuclear Power Plants,” Revision 1. Regulatory Guide 1.61, Section D, “Implementation,” provided information to licensees for use of the Regulatory Guide. Section D stated that the NRC would use the methods in the guide to evaluate submittals from operating reactor licensees who voluntarily propose to initiate system modifications if there is a clear nexus between the proposed modification and the subject for which guidance is provided. Regulatory Guide 1.61 did not include provision for the use of the guide without prior NRC approval.

NEI 96-07, Section 4.3.8, permitted the use of a new NRC approved methodology to reduce uncertainty, provide more precise results, or other reason, provided the 50.59 evaluation demonstrated the following:

> (a) based on sound engineering practice,
> (b) appropriate for the intended application, and
> (c) within the limitations of the applicable NRC safety evaluation report.

Item (c) required the licensee to demonstrate that use of the new methodology, Regulatory Guide 1.61, provided results that were essentially the same as, or more conservative than, either the previous revision of the same methodology or another methodology previously accepted by NRC through issuance of a safety evaluation report. The licensee’s evaluation did not address how the change was consistent with the limitations of applicable NRC safety evaluation reports. The inspectors concluded that the LBIE 2009-021 was less than adequate to demonstrate that prior NRC approval was not required to incorporate the new seismic damping values into the replacement reactor head. On December 14, 2009, Pacific Gas and Electric submitted Licensee Amendment Request 09-06, “Critical Damping Value for Structural Dynamic Qualification of the Control Rod Drive Mechanism Pressure Housings,” to the NRC requesting approval to use a damping value of 5 percent on the replacement reactor head modification.

<u>Analysis</u>. The failure of Pacific Gas and Electric to perform an adequate 10 CFR 50.59 evaluation, in accordance with NEI 96-07, prior to changing the facility as described in the FSARU is a performance deficiency. The inspectors evaluated this issue using the traditional enforcement process, including NRC Enforcement Policy, Supplement I, Reactor Operations, because the performance deficiency had the potential for impacting

the NRC's ability to perform its regulatory function. The inspectors concluded that the issue was more than minor because of reasonable likelihood the change to the facility would require Commission review and approval prior to implementation. The inspectors also evaluated the significance of this issue under the Significance Determination Process using Inspection Manual Chapter 0609.04, "Phase 1 - Initial Screening and Characterization of Findings." The inspectors concluded that the issue affected the Initiating Events Cornerstone because the change decreased the structural integrity of the control rod drive mechanism reactor coolant pressure barrier and screened Green because assuming worst case degradation, the finding would not result in exceeding the technical specification limit for reactor coolant system leakage nor have a likely effect on other mitigation systems resulting in a total loss of their safety function. The inspectors concluded that the violation was a Severity Level IV because the issue screened Green under the Significance Determination Process. The finding has a crosscutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee did not thoroughly evaluate the original problem with the replacement reactor head design such that the resolutions address causes and extent of conditions, as necessary [P.1(c)].

Enforcement. Title 10 CFR 50.59, "Changes, Tests and Experiments," stated that a licensee may make changes in the facility as described in the FSARU without obtaining a license amendment if the change does not result in a departure from a method of evaluation described in the FSARU used in establishing the design bases or the safety analyses. Contrary to the above, on November 5, 2009, Pacific Gas and Electric changed the facility as described in the FSARU to incorporate increased seismic damping for use in the replacement reactor head design without obtaining a license amendment. Because this finding is of very low safety significance and was entered into the corrective action program as Notification 50276288, this violation is being treated as a noncited violation in accordance with Section VI.A.1 of the Enforcement Policy: NCV 05000323/2009005-05, "Less than Adequate Change Evaluation to the Facility as Described in the Final Safety Analysis Report Update."

.7 Unresolved Item: 05000275;323/2009003-01 - Corrective Action Following Degraded Offsite Power System

Introduction. On April 10, 2009, the inspectors identified that the plant electrical analysis may not be adequate to demonstrate that the 230 kV preferred offsite power system had sufficient capacity and capability to meet design basis loading requirements. This issue was unresolved (Unresolved Item: 05000275;323/2009003-01) pending additional NRC review.

Discussion. Pacific Gas and Electric used Calculation 357AA-DC, "Units 1 and 2 Load Flow, Short Circuit and Motor Starting Analysis," September 24, 2007, to ensure that the preferred offsite power system was capable of meeting design basis electrical load requirements. The inspectors identified that Calculation 357AA-DC did not include load flow cases representing the largest total capability for an accident on one unit and concurrent safe shutdown of the other unit or concurrent safe shutdown of both units. The licensee stated that the cases modeled in the load flow were based on the assumption that plant operators would perform an "orderly shutdown" on the non-accident unit. This assumption allowed the electrical designers to limit the demand on the offsite power system considered in the loading analysis by modeling loads from the non-accident unit manually transferred to the 230 kV system at a time of low electrical demand from the accident or tripped unit.

The inspectors identified that the licensee's assumption of an "orderly shutdown" appeared inconsistent with the Diablo Canyon design basis. NRC Safety Evaluation Report, "Safety Evaluation by the Directorate of Licensing U.S. Atomic Energy Commission in the Matter of Pacific Gas and Electric Company Diablo Canyon Nuclear Power Station, Units 1 and 2 San Luis Obispo County, California Docket Nos. 50-275 and 50-323," and FSARU, Section 8.1, "Offsite Power Systems," established IEEE Standard 308-1971, "Class IE Electrical Systems," as part of the preferred offsite power system design basis. IEEE Standard 308-1971, Section 8.1.1, "Multi-Unit Station Considerations," stated:

> "Capacity. A multi-unit station may share preferred power supply capacity between units. In such a case, as a minimum the total preferred capability must be sufficient to operate the engineering safety features for a design basis accident on one unit and those systems required for concurrent safe shutdown on the remaining units. The type of accident and shutdown and the unit assumed to have the accident, shall be those which give the largest total preferred capability requirements."

Pacific Gas and Electric previously identified that the 230 kV offsite power source had insufficient capacity (reported as Licensee Event Report 1-95-007, "230 kV System May Not Be Able to Meet Its Design Requirements for all Conditions Due to Personal Error)." The corrective actions included modifications to the 230 kV system, including installation of new startup transformers and large capacitors banks. Pacific Gas and Electric re-evaluated the 230 kV design basis requires prior to scoping these modifications. In a "Licensing Position" paper for the 230 kV system loading requirements (Letter File #227961, from the Director, Licensing to Director, Electrical I&C Engineering September 27, 1995), the licensee changed "concurrent" to "orderly" shutdown in the implementation of the IEEE 308-1971 requirements.

On June 10, 2009, the inspectors identified that the licensee's FSARU change from "concurrent" to "orderly" shutdown did not have an 10 CFR 50.59 safety evaluation and may have required prior NRC approval. The licensee entered this issue into the corrective action program as Notification 50248299. On July 4, 2009, the licensee concluded that prior NRC approval was not required because this change was included as supplemental information with License Amendment Request 98-01, in the form of marked up FSAR pages and response to NRC questions. The licensee stated that they considered NRC approved of the change because the NRC subsequently approved the License Amendment Request.

On February 23, 2009, and supplemented by letter dated September 14, 2009 (ADAMS Accession Numbers ML090650592 and ML092650289) Pacific Gas and Electric requested that the NRC concur with its position regarding the capacity and capability of the Diablo Canyon offsite power system. The licensee requested, in part, that the NRC concur with the assumption that the licensing basis is limited to an "orderly shutdown" rather than a "concurrent" shutdown of the non-accident unit. By letter dated December 14, 2009 (ADAMS Accession Nos. ML093130428), the NRC staff disagreed with the licensee's position. The NRC letter stated:

"During its review, the NRC staff identified that the licensee made changes to the DCPP licensing basis without following the regulatory requirements at 10 CFR 50.59, "Changes, tests and experiments." Within 15 months of revising the language of the design-basis coping response for the dual unit DCPP site, the licensee submitted the same changes to the NRC staff for review as LAR 98-01. Specifically, the licensing basis changed from"... safe shutdown of the second unit" to "...orderly shutdown of the second unit." Using the revised language during a design-basis accident would allow the electric generator of the second (non-accident) unit to remain synchronized with the offsite transmission system and thereby continue to receive 500 kV offsite power until the unit generator output was eventually reduced to the point of separating from the 500 kV offsite system. This change would reduce the analyzed maximum loading on the 230 kV offsite electrical system by eliminating the post-trip electrical loading to the second unit which, if tripped, would also require station service power from the 230 kV system for up to 30 minutes after initiation of the event."

"Thus, this change eliminated the need to consider the 30-minute post-trip loading of the 230 kV system for the second unit because an "orderly shutdown" of the unit is expected to take greater than 30 minutes to complete. The inappropriate unilateral change subsequently caused the licensee to submit inaccurate information to the NRC staff related to the 230 kV system licensing basis in LAR 98-01 and in the subject TS interpretation."

The licensee implemented corrective actions to address the safety aspects of the issue (Notification 50289590). The licensee revised the 230 kV offsite power grid stability evaluation to include a dual unit trip in study, "Requirements for Offsite Power Supply Performance Under Dual Unit Trip Conditions," November 23, 2009. The licensee reviewed limitations of the revised analysis with the plant operating organization, scheduled a revision to Design Calculation 357AA-DC to add the limiting load cases, and reviewed past system operability.

The issue continues to be unresolved pending completion of additional NRC review of past 230 kV system operability. Also, NRC evaluation of the information provided by the licensee with License Amendment Request 98-01 and by letters (February 23 and September 14, 2009) to determine if this information had been complete and accurate at the time submitted would likely have resulted in a reconsideration of a regulatory position or resulted in substantial further inquiry.

.8 <u>(Discussed) NRC – Review of the Shoreline Fault and Evaluation of the Potential Impact on Plant Systems</u>

On November 21, 2008, Pacific Gas and Electric notified the NRC of the discovery of a geologic feature that may represent a new earthquake fault (Event Notification 44675). In December 2008, Pacific Gas and Electric developed an action plan to fully characterize the Shoreline Fault. This action plan and schedule is available in ADAMS (ML083540266, ML090720505, ML090720516, and ML083540261). On December 15, 2009, Pacific Gas and Electric provided the inspectors a summary of shoreline fault characterization activities conducted over the past year. The licensee concluded that the postulated ground movement spectrum was bounded by the current plant seismic design and licensing bases.

The licensee concluded that the shoreline feature is a vertical, strike-slip fault with a 10 km depth. The fault zone is located within 300 meters from the plant intake structure and 600 meters from the Diablo Canyon power block. While the fault line extends north of the plant and intercepts with the Hosgri Fault, licensee geophysicists concluded that the northern section of the feature has a negligible activity rate, such that it is classified as inactive. Based on this assumption, ground motion (deterministic at 84^{th} percentile using the margin approach and assumed fault rupture models) could result in a magnitude 6.25 event. The licensee concluded that secondary ground deformation following a fault rupture would not affect essential buried plant piping. Using a probabilistic approach and a calculated slip-rate 0.01 to 0.3 mm/year, secondary deformation in the shale unit has an extremely low probability. The NRC will continue to monitor and independently evaluate Pacific Gas and Electric and United States Geological Survey characterization of the Shoreline Fault.

.6 <u>(Closed) Unresolved Item URI 05000275,323/2006009-01, "Assessing and Managing Maintenance Risk for Post-Fire Safe Shutdown Equipment."</u>

This unresolved item involves external event risk. The issues identified affect all nuclear power plants and will receive the reviews required for generic requirements (e.g., a backfit analysis). Depending upon the results of that analysis, the issue might be revisited. Consequently, this unresolved item is being administratively closed.

4OA6 Meetings

<u>Exit Meeting Summary</u>

On October 21, 2009, the inspectors presented the in-service inspection activities results to Mr. L. Sharp, Engineering Services, Senior Director, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On December 10, 2009, the inspectors presented the onsite emergency preparedness inspection results to Mr. J. Becker, Site Vice President, and other members of the licensee's staff. The licensee acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On December 17, 2009, the inspectors presented the inspection results to Mr. C. Harbor, acting Station Director, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On January 4, 2010, the inspectors presented the inspection results to Mr. J. Becker, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

Title 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” states, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with those procedures. On August 12, 2009, plant operations management failed to implement Section 5.4.5 of safety-related Procedure OP1.ID3, “Reactivity Management Program.” The procedure states information provided by reactor engineering such as rod movement recommendations, reactivity management plans, ramp plans, and reactivity briefing sheets shall be provided to the control room via an operations shift order. Contrary to this, an unapproved Reactor Engineering Ramp Plan was utilized by control room staff for approximately two hours during a downpower and subsequent shutdown of Unit 2 reactor for emergent transformer repairs. The unapproved Reactor Engineering Ramp Plan was a draft copy utilized for the operations crew just-in-time simulator training for the shutdown, and was subsequently used in the control room by mistake. The approved Reactor Engineering Ramp Plan was available in the control room at the start of the ramp; however, it was not initially utilized. Upon discovery of the unapproved plan by the control room staff, the approved (correct) plan was then used for the remainder of the shutdown. Pacific Gas and Electric entered the issue into their corrective action program as Notification 50262580. The finding is of very low safety significance because no reactivity manipulations outside of the approved plan had been made prior to discovery by the control room staff.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Baldwin, Manager, Regulatory Services
J. Becker, Site Vice President
J. Ferguson, ALARA Supervisor, Radiation Protection
J. Fledderman, Strategic Projects, Director
M. Ginn, Manager, Emergency Preparedness
W. Ginter, Strategic Projects, Project Manager
W. Guldemond, Director, Site Services
C. Harbor, Acting Station Director
S. Ketelsen, Manager, Regulatory Services
M. Lanni, Coordinator, ALARA
L. Parker, Regulatory Services, Acting Manager
K. Peters, Station Director
D. Peterson, Quality Verification, Director
L. Sharp, Engineering Services, Senior Director
M. Somerville, Manager, Radiation Protection
T. Swartzbaush, Manager, Operations
J. Welsch, Director, Operations Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

05000275;05000323/2515/172	TI	Reactor Coolant System Dissimilar Metal Butt Welds (Section 4OA5.2)
05000275,05000323/2006009-01	URI	Assessing and Managing Maintenance Risk for Post-Fire Safe Shutdown Equipment (Section 4OA5.6)
05000323/2009-001-00	LER	Technical Specification 3.0.3 One Hour Exceeded Due to Failure of Group Step Counters (Section 4OA3.2)
05000323/2009-002-00	LER	Technical Specification 3.7.1 Violation Due to Cracked Valve Spring (Section 4OA3.3)

Opened and Closed

05000323/2009005-01	NCV	Less Than Adequate Work Planning Resulted in the Release of Two Gas Decay Tanks (Section 1R20)
05000323/2009005-02	NCV	Failure to Properly Plan a Maintenance Activity (Section 2OS2)
05000275,05000323/2009005-03	NCV	Inadequate 50.59 Evaluation for Steam Generator Tube Rupture Analysis (Section 4OA2)
05000323/2009005-04	NCV	Less than Adequate Replacement Reactor Head Modification Design Control (Section 4OA5.3)
05000323/2009005-05	NCV	Less than Adequate Change Evaluation to the Facility as Described in the Final Safety Analysis Report Update (Section 4OA5.6)

Discussed

05000275,05000323/2009003-01	URI	Corrective Action Following Degraded Offsite Power System (Section 4OA5.7)
		Review of Shoreline Fault and Evaluation of Potential Impact on Plant Systems (Section 4OA5.8)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

PROCEDURES

NUMBER	TITLE	REVISION
OP AP-10	Loss of Auxiliary Salt Water	9
CP M-5	Response to Tsunami Warning	14

Section 1R04: Equipment Alignments

PROCEDURES

NUMBER	TITLE	REVISION

OP J-6B	Diesel Generators	9
STP M-81H	Diesel Engine Generator Inspection	4

ACTION REQUESTS/NOTIFICATIONS

A0738710	50262868	50262867	50264138	50253152

Section 1R05: Fire Protection

PROCEDURES

NUMBER	TITLE	REVISION
OM8.ID4	Control of Flammable and Combustible Materials	17

ACTION REQUESTS/NOTIFICATIONS

A0738352	A0737627	50041830	A0697020

Section 1R06: Flood Protection Measures

PROCEDURES/DOCUMENTS

NUMBER	TITLE	REVISION/DATE
DCL-07-053	90-day Response to NRC Generic Letter 2007-01	May 2, 2007
Dwg 500615	General Arrangement of Electrical Pull Boxes and Duct Runs	4
Dwg 500820	Electrical Pull Boxes and Duct Runs	10
Calc. M-550	Re-analyze Flood Elevations from Postulated HELB/MELB in GE/GW Area and RHR Pump Rooms	3

NOTIFICATION

50276052

Section 1R08: Inservice Inspection Activities

PROCEDURES

NUMBER	TITLE	REVISION/DATE
STP R-8C	Containment Walkdown for Evidence of Boric Acid Leakage	8A
AD4.ID2	Plant Leakage Evaluation	10
ER1.ID2	Boric Acid Corrosion Control Program	4

ISI X-CRDM	Reactor Vessel Top and Bottom Head Visual Inspections	5
OM7.ID1	Problem Identification and Resolution	31
NDE ET-7	Eddy Current Examination of Steam Generator Tubing	13
54-ISI-400-17	Multi-frequency Eddy Current Examination of Tubing	Jan. 26, 2009
ETSS #1	Examination Techniques Specification Sheet	
NDE PDI-UT-2	Ultrasonic Examination of Austenitic Piping	6
WPS 51	Welding of P8 Materials with GTAW and/or SMAW ASME III, RegGuide 1.44[b]	8

NOTIFICATIONS

50271737	50271790	50271803	50274424	50038986
50273822	50273822	50273967		

NDE REPORTS

NUMBER	TITLE	DATE
22-A4-0168-2, Oper. 0350	RT WH-11	Mar. 30, 2009
22-A5-0168-2, Oper. 0600	PT WH-12	Apr. 13,2009
22-A1-0168-2, Oper. 1000	VT WH-2 First/Final Layer Cladding	Nov. 15, 2007
22-A1-0168-2, Oper. 1550	WH-3, UT Report Clad Thickness	Nov. 29, 2007
22-A1-0168-2, Oper. 2250	WH-5, UT Final Surface Bond and Defect	Feb. 12, 2008
22-D1-0168-2, Oper. 2100	UT Under Clad Cracking	Feb. 4, 2009
22-D1-0168-2, Oper. 2200	PT Dissimilar Metal Welds ILH, TC, Vent, and RVLIS	Jan. 22, 2009
22-D1-0168-2, Oper. 2800	VT WH-009 and WH-010	Feb. 5, 2009
22-E1-0168-2, Oper. 1350	PT Final WH-13	May 17, 2009
22-A4-0168-2, Oper. 0650	RT WH-12	Apr. 14, 2009
WIB-368-369	UT of Pressurizer Safety Nozzle A Weld Overlay	Oct. 8, 2009
WIB-422A-423	UT of Pressurizer Safety Nozzle B Weld Overlay	Oct. 10, 2009
WIB-358-359	UT of Pressurizer Safety Nozzle C Weld Overlay	Oct. 10, 2009
WIB-379-380	UT of Pressurizer Relief Nozzle Weld Overlay	Oct. 10, 2009
WIB-345-346	UT of Pressurizer Spray Nozzle Weld Overlay	Oct. 10, 2009

WIB-438-439	UT of Pressurizer Surge Nozzle Weld Overlay	Oct. 10, 2009

Section 1R11: Licensed Operator Requalification Program

PROCEDURES

NUMBER	TITLE	REVISION
E2ECA21-A	Loss of 4kV Bus/Excessive Steam Demand/ATWS	17

Section 1R12: Maintenance Effectiveness

NOTIFICATIONS

50044666	50264326	50267081	50252762	50044666
50241125	50264326			

OTHER DOCUMENTS

NUMBER	TITLE	DATE
63	Maintenance Rule Expert Panel Meeting Minutes	Sept. 16, 2009

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

PROCEDURES

NUMBER	TITLE	REVISION
OP O-36	Protected Train Restrictions	2

NOTIFICATIONS

50284530	50274376	50275757

Section 1R15: Operability Evaluations

PROCEDURES/DOCUMENTS

NUMBER	TITLE	REVISION
OM7.ID1	Problem Identification and Resolution	31
OM7.ID13	Technical Evaluations	0
ECG 23.1	Ventilation and Air Conditioning	5
Dwg. 106723	Control Room HVAC (North)	98

ACTION REQUESTS/NOTIFICATIONS

50265431	A0733045	A0521245	50274212	50286770
50286710	50287187	50274218	50286939	50274645

Section 1R15: Operability Evaluations

PROCEDURES/DOCUMENTS

NUMBER	TITLE	REVISION
50274452		

Section 1R18: Plant Modifications

PROCEDURES

NUMBER	TITLE	REVISION
CF4	Modification Control	6
CF4.ID7	Temporary Alteration	20

NOTIFICATIONS

50231267	50232855	50229650

Section 1R19: Postmaintenance Testing

PROCEDURES

NUMBER	TITLE	REVISION
STP M-9A	Diesel Engine Generator Routine Surveillance Test	81
STP P-SIP-12	Routine Surveillance Test of Safety Injection Pump 1-2	21A
STP P-RHR-21	Routine Surveillance Test of RHR Pump 2-1	23
PEP V-7B	Test of ECCS Valve Interlocks	1

ACTION REQUESTS/NOTIFICATIONS

50288138	50289644	A0672618	A0689300	A0592204
A0337998				

Section 1R20: Refueling and Other Outage Activities

PROCEDURES

NUMBER	TITLE	REVISION
OP A-2:VIII	Clearing and Draining ECCS Systems for the Core Offload Window	12
	2Y15 Outage Safety Plan	0

NOTIFICATION

50280826

Section 1R22: Surveillance Testing

PROCEDURES

NUMBER	TITLE	REVISION
STP R-1C	Reactor Coolant System Water Inventory Balance	6
STP P-CCW-A13	Comprehensive Pump Test of Component Cooling Water Pump 1-3	1
STP V-656	Penetration 56 Containment Isolation Valve Leak Testing	10
STP V-645	Penetration 45 Containment Isolation Valve Leak Testing	22
STP V-600	General Containment Isolation Valve Leak Tests	22

NOTIFICATIONS

50283779 50275191

Section 1EP2: Alert Notification System Testing

PROCEDURES

NUMBER	TITLE	REVISION
EP MT-43	Early Warning System Testing and Maintenance	9
STP I-29	Emergency Signals and Communications Systems Functional Test	39

Section 1EP3: Emergency Response Organization Augmentation Testing

PROCEDURES

NUMBER	TITLE	REVISION
OM10.DC1	Emergency Preparedness Drills and Exercises	5
OM10.ID1	Maintaining Emergency Preparedness	8

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

AUDITS AND SELF-ASSESSMENTS

TITLE	DATE
Quick Hit Self Assessment	Dec. 1, 2009
Quality Performance Assessment Report Third Period 2007	Jan. 7, 2008
Quality Performance Assessment Report First Period 2008	May 15, 2008
Quality Performance Assessment Report Third Period 2008	Dec. 31, 2008
Quality Performance Assessment Report First Period 2009	May 21, 2009

Quality Performance Assessment Report Second Period 2009	Sept. 10, 2009
2009 Emergency Plan 10 CFR 50.54(t) Assessment	May 28, 2009
Self Assessment: 2008 Emergency Preparedness Program 50.54(t) Review	Apr. 21, 2008
Self Assessment: Diablo Canyon Emergency Preparedness	Dec. 29, 2008

ACTION REQUESTES/NOTIFICATIONS

50232836	50256130	50243810	50086019	50247125
50080645	50042154	50099595	50084930	50116346
50082593	50075781	50247132	50041231	50041647
50082563	50183552	50275227	50276035	50286430
50286847	50274786	50288055	50288152	50288148
A0730221	A0708103	A0735898		

Section 2OS1: Access Controls to Radiologically Significant Areas

PROCEDURES

NUMBER	TITLE	REVISION
RP1	Radiation Protection	5
RCP D-220	Control of Access to High, Locked High, and Very High Radiation Areas	36
RCP D-240	Radiological Posting	19

NOTIFICATIONS

50212673	50241708	50272896	50282039

Section 2OS2: ALARA Planning and Controls

PROCEDURES

NUMBER	TITLE	REVISION
RCP D-200	ALARA Planning and Controls	47
RCP D-201	Writing Radiation Work Permits	1
RP1.ID1	Requirements for the ALARA Program	6

Section 2OS2: ALARA Planning and Controls

PROCEDURES

NUMBER	TITLE	REVISION
RP1.ID9	Radiation Work Permits	10
AD7.ID6	Nuclear Generation/Supplemental Personnel Interface	6

NOTIFICATIONS

50212671	50212674	50231155	50234045	50239804
50243470	50255576	50259921	50273892	50276004

RADIATION WORK PERMITS

RWP #	DESCRIPTION
09-2067	SI Testing Optimization Project
09-2230	2R15 Rx Head Project Support Activities
09-2231	2R15 Rx Head Project Equipment Staging and Transport (not for use in Contaminated Areas)
09-2232	2R15 Rx Head Project Equipment Staging (for use in Contaminated Areas)
09-2233	2R15 Rx Head Project ORVCH Disassembly (AREVA)
09-2234	2R15 Rx Head Project ORVCH Removal from Containment
09-2235	2R15 Rx Head Project Transport and Storage of the ORVCH in the Mausoleum
09-2236	2R15 Rx Head Project NRVCH Assembly (AREVA)
09-2237	2R15 Rx Head Replacement Project Scaffolding Support

SAMPLE RESULTS AND SURVEYS

SURVEY #	DESCRIPTION
6589	Initial Entry Upper Cavity/Top of Rx Head
6738	U2 Rx Head Detensioning
6856	Down Posting from LHRA to HRA around U2 Reactor Head on Head Stand
6944	Update Dose Rates Due to Removal of DPRI Coils and Scaffold around Rx Head
6962	Job Coverage 13 DPRI (Coils) Left to Remove Rx Head

7188	Personnel Contamination Event
7192	Personnel Contamination Event
7211	Personnel Contamination Event
7224	2R15 Containment 91’ SG 2-1 HEPA Exhaust Verification

MISCELLANEOUS

NUMBER	TITLE	DATE
RCP D-200 – Attachment 10.5	ALARA Post job Review – RWP 09-2067 – SI Testing Optimization Project	May 29, 2009
Form 69-20108	FSAR Change Request – Storage Facility of ORVCH in Mausoleum	April 2, 2008

Section 4OA1: Performance Indicator Verification

PROCEDURES

NUMBER	TITLE	REVISION
XI1.DC1	Collection and Submittal of NRC Performance Indicators	9A
AWP EP-001	Emergency Preparedness Performance Indicators	12
AWP O-002	NRC Performance Indicator: RETS/ODCM Radiological Effluent Occurrences	9
AWP O-003	NRC Performance Indicators: Occupational Exposure Control Effectiveness	5

DRILL AND EXERCISE REPORTS

TITLE	DATE
Training and Qualification Table Top Drill Report	Mar. 7, 2007
ERO Bravo Team Facility Activation/Rapid Response Test	June 8, 2007
Summer Table Top Evaluated Drill Report	June 27, 2007 July 25, 2007
2007 Annual Drill Report Bravo Team	Sept. 18, 2007
2008 Table Top Drill Alpha Team	May 28, 2008
2008 Table Top Drill Charlie Team	May 28, 2008
2008 Table Top Drill Bravo Team	Aug. 13, 2008
2008 Dress Rehearsal Bravo Team	Sept. 24, 2008
2009 NRC Evaluated Exercise	Oct. 29, 2008
ERO Team Alpha Full-Scope Drill	May 27, 2009
Alpha Team Rapid Response Table Top Drill	May 5, 2005

EVENT REPORTS

Unusual Event HU2.1 Event Summary Report	July 21, 2008
Unusual Event HU2.1 Event Summary Report	Aug. 17, 2008
Unusual Event HU2.1 Event Summary Report	June 2, 2009

Section 4OA5: Other Activities

IP 71007 – Reactor Vessel Head Replacement

PROCEDURES/DOCUMENTS

NUMBER	TITLE	REVISION/DATE
NS-VICO-03-01	CRDM Cable and Connector - Testing	1
NSD-EIS-98-008	DRPI Coil Stack Upgrade & Testing – Butt Spliced Leads	7
NS-FSI-08-12	DRPI System Data Cabinet Cable/Connector Replacement – Unit 2	1
NSD-EIS-97-15	DRPI Cable and Connector Upgrade – Final Testing	5
MP M-7-RX.5	Westinghouse Core Exit Thermocouple Nozzle Assembly Opening and Closure	0
MP M-7-RX.6	Reactor Vessel Closure Head Installation	0
MP I-2.21-1B	Reactor Vessel head Installation – Connecting Incore Thermocouple Cables	0

MP I-2.21-4B	Reactor Vessel Head Installation – Connecting Head Vent Valves Cables	0
MP I-2.21-5B	Reactor Vessel Head Installation – Connecting CRDM Cables	0
MP I-2.21-6B	Reactor Vessel head Installation – Installing RVLIS Upper Sense Line	0
STP I-91B	Thermocouple Monitoring System Channel Calibration	11
MP I-2.21-7B	Reactor Vessel Head Reinstallation – Connecting CRDM Cooling System I&C Cables	0
STP I-50-Y130.1	DRPI Logic Channel Functional Test	5
STP I-50-Y130.2	DRPI Indication Channel Functional Test and Detector Integrity Test	10
MP I-2.21-2B	Reactor Vessel Head Installation – Connecting DMIMS Cables	0
PEP R-1D	Control Rod Exercising for CRDM Crud Mitigation	1
MP E-50.1	Thermal Overload Relay and Cubicle Maintenance	41
STP I-7-Y243.B	PPC Rod Control Bank Indication Test	5
MP M-42-POL	Polar Crane Maintenance	2
MP M-7.50	In-Place Reactor Head Vent Valve Seat Leakage Test	8
MP E-53.8	Maintenance of Reactor Head Vent Valves	13
MP M-56.1	System Pressure Test	16
STP I-87B5	Reactor Vessel level Indication System DP3 Normalization Procedure	7
MP I-1.6-8	Rod Control DC Hold Test	2
STP R-8A	Reactor Coolant System Leakage Test	14
STP R-8C	Containment Walkdown for Evidence of Boric Acid Leakage	8A
STP R-1B	Rod Drop Measurement	33
STP R-27	Incore Thermocouples and RCS RTD Cross Calibration	27
STP I-87B	RVLIS/SCMM Computer Input/Output Channel Calibration	5
MP I-1.6-5	Rod Control Slave Cycler Current Order Timing Verification	3

MP I-1.6-6	Rod Control Current Order and Coil Regulation Verification	4
MP M-50.16	Special Service Hoists, Jib Cranes and Monorails Inspection	7
Order #68004824	Perform DRPI Testing on Head Stand	July 22, 2008
Order #68006480	Test Abraded DRPI Cables on IHA Bridge	July 22, 2008
Order #68004240	Modify DRPI Detectors	July 22, 2008
Order #68004063	Rx Head Project-Hydro & Seat Leakage	July 22, 2008
Order #68007283	DRPI Detector Inspect/Repair As Required	July 22, 2008
AD1.1D1	Nuclear Generation Procedure Writers Manual	17
OM7.ID1	Problem Identification and resolution	31
EOP E-0	Reactor Trip of Safety Injection	36
EOP E-3	Steam Generator Tube Rupture	31
IDAP XI3.ID2	FSAR Update Change Request	Dec. 2, 1992
NCR DCO-92-NS-N006/0	SGTR Analysis	Apr. 3, 1992
PGE-92-685	SGTR Margin to Overfill Re-Analysis	Oct. 13, 1992
WCAP-10698-P-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill	Aug. 1987
DCL-91-009	SGTR Analysis Operator Action Times	Jan. 17,1991
DCL-88-114	SGTR Analysis	Apr. 29, 1988
E3ECA33-D	SGTR Simulator Evaluation Guide	15
OP1.ID2	Time Critical Operator Action	1A
PGE-01-535	SGTR Re-Analysis Report	Oct. 26, 2001
DCL-92-244	SGTR Analysis Deficiency due to Inadequate Communications with NSSS Supplier	Oct. 30, 1992

NOTIFICATIONS

50038542	500040282	50040276	50085800	50034874
50034871	50125848	50280803	50281724	50275213
50270786	50237461			

MISCELLANEOUS

NUMBER	TITLE	DATE
072200051	PG&E Quality Assurance Surveillance of BWXT Inc.	Sept. 17, 2007
071000024	Source Surveillance of BWXT Inc. Mt Vernon, IN	Apr. 18, 2007
071000025	PG&E Quality Verification Surveillance Report,	July 23, 2007

MISCELLANEOUS

NUMBER	TITLE	DATE
	RRVCH Component Fabrication at Japan Steel Works, Muroran, Japan	
9058577	AREVA, RVCH – Diablo Canyon 2 BWXT Surveillance	Oct. 8, 2007
072200051	PG&E Quality Assurance Surveillance of B&W Nuclear Operations Division	Sept. 29, 2008
080150001	PG&E Quality Assurance Surveillance of B&W Nuclear Operations Division	Jan. 23, 2008
081910104	PG&E Quality Assurance Surveillance of B&W Nuclear Operations Division	Aug. 4, 2008
090430005	PG&E Quality Assurance Surveillance of DCPP RVCH Fabrication: B&W Nuclear Operations Division, Mt. Vernon, IN	Mar. 30, 2009
082240023	PG&E Quality Assurance Surveillance of DCPP RVCH Fabrication: B&W Nuclear Operation Division, Boyd Machine and Repair Co., and Patriot Forge Co.	Dec. 8, 2008
080910009	PG&E Quality Assurance Surveillance of B&W Nuclear Operations Division	Apr. 2, 2008

PROCEDURES

NUMBER	TITLE	DATE
072200051	PG&E Quality Assurance Surveillance of BWXT Inc.	Sep. 17, 2007